

An Integrated Resource Plan for South Africa using Electricity Load Profiles

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ABSTRACT

Integrated resource planning aims to fulfil electricity requirements with supply and demand resources. Least cost resources are optimised as supply expansions compete with measures to modify the load in meeting energy services. A demand side study is conducted to determine representative load profiles for electricity use within South Africa. Analysis of electricity consumption using load profiles of each sector's end-use electrical loads is essential for determining the appropriate supply technologies as well as the impact of demand side management and energy efficiency measures. A supply side study considers all existing and future power generation options required for expected electricity growth and system load characteristics. Energy model, TIMES, provides time-slices for adequate load profile representation. TIMES is a Partial Dynamic Equilibrium Model as constraints are placed on the investment, usage and availability of technologies. All optimisations are for the least cost to the system. Demand and supply options are integrated into a single plan using the TIMES model and the supply expansion plan is changed when demand reduction targets are achieved using DSM and EE.

The base case using a business-as-usual approach is compared with a low and medium impact DSM and EE scenario. Demand resources are estimated from the industrial, commercial and residential economic sectors. The scope of the plan is 22 years and there is full utilisation of all existing supply capacity with small amounts of decommissioning. Mothballed power stations are recommissioned initially. Peak-load plants are needed from 2007 and OCGT are selected using natural gas or LNG. Intermediate-load capacity is needed by 2011 using CCGT. Base-load capacity demands are met using new coal PF power stations in 2014. FBC stations using discard coal begin operation in 2016. The capacity expansion plan anticipates 2.93GW of OCGT, 2.5 GW of CCGT, 7.2GW of coal PF, 2.8 GW of FBC plants and 2 GW of pump storage stations to be in use by 2020. Imported hydroelectric capacity of 0.9 GW and PBMR capacity of 3 GW is expected to be commissioned by 2024. Approximately 4% less installed capacity is needed when a medium impact DSM and EE strategy is implemented. The marginal cost of energy gradually increases from 0.06 R/kWh in 2002 to 0.175 R/kWh in 2016 and to 0.325 R/kWh in 2024 as supply capacity is added. Compound load profiles from all national electricity usage provide an effective means whereby appropriate supply technologies are selected whilst incorporating load modifications due to DSM and EE.

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Glossary of Acronyms

CCGT	Combined Cycle Gas Turbine
CCT	Clean Coal Technology
CFL	Compact Fluorescent Lighting
CO₂	Carbon dioxide
DME	Department of Minerals and Energy
DSM	Demand Side Management
EE	Energy Efficiency
ESCo	Energy Services Company
ESKOM	Eskom Holdings Limited
FBC	Fluidised Bed Combustion
FGD	flue gas desulphurisation
GDP	Gross Domestic Product
GHG	Greenhouse Gasses
GT	Gas Turbine (OC- open cycle)
HVAC	Heaving, Ventilation and Cooling
IEP	Integrated Electricity Plan
IPP	Independent Power Producer
IRP	Integrated Resource Planning
LCP	Least Cost Planning
LNG	Liquefied Natural Gas
LPG	Liquid Petroleum Gas
LRMC	Long Run Marginal Cost
MEC	Marginal Energy Cost
MCC	Marginal Capacity Cost
N₂O	Nitrous oxide
NER	National Energy Regulator
NIRP	National Integrated Resource Plan
PBMR	Pebble Bed Modular Reactor
PF	Pulverised Fuel (coal-fired)
RDP	Reconstruction and Development Programme
TIMES	The Integrated MARKAL/EFOM system
TOU	Time-Of-Use (tariff)
VSD	Variable Speed Drive (motor)

1 Introduction

Integrated resource planning (IRP) considers both demand and supply planning to meet the need for energy services. South African electricity power planning has been focussed on supply generation technologies in the past. The governmental White Paper on the Energy Policy of 1998, promotes IRP for effective use of all resources. The environment for the inclusion of demand side resources is opening up due to a shortage of existing generation and transmission capacity. South Africa's electricity supply industry is undergoing restructuring and demand side options can be an integral part of least-cost planning (LCP) in a more competitive electricity supply industry. Eskom, the national electricity supplier, developed an integrated electricity plan (IEP) in 1996 that enumerated Demand Side Management (DSM) potentials for various sectors. The first national IRP was conducted in 2001 and considered demand options in addition to the conventional supply options [NIRP 2001]. The second IRP was the National Integrated Resource Plan (NIRP) of 2003, which plans for energy efficiency and load management in the various sectors and specifies the energy use where these savings occur. This study utilises load profiles of consumer electricity demands in an integrated resource plan so that resources can be analysed and their use optimised based on a minimisation of total system cost.

IRP is defined as the planning operation of combined developments of electricity supplies and demand side management (DSM) and energy efficiency (EE) options to provide energy services at a minimum cost where environmental and social costs are also included [Swisher et al 1997]. A comprehensive IRP is when all technologically feasible supply and demand options are considered in a capacity expansion plan. A demand side study is needed initially to establish how much load capacity will be demanded and what load's usage could be changed by DSM and EE programs. Demand side management is defined as the measures implemented by a utility to influence changes in the consumers' energy use behaviour and can include the use of financial incentives such as tariff structuring and load management. Energy savings through EE is a broader demand side option because programs could be initiated by governments or the utility and affect a wider product range. Consumers benefit by paying for less energy in meeting the same service and society benefits by using less energy resources.

A database of each economic sector's electricity requirements provides the data for the IRP. Yearly load profiles are used to represent the electricity usage for each load type within every sector. Load profiles show how much electricity (WattHours) is used by a specific load for a period of time as power (Watts) is plotted against time (hours). There is a lack of detailed and accurate data on how electricity is used and extrapolation methods are used to build a national database. The growth of each sector's electricity consumption is projected for 20 years. The database provides the input data to a supply expansion plan in addition to demand based initiatives that could change the load profile.

A detailed load profile analysis could establish the potential and possible impact of DSM and EE for a particular end-use within a sector or nationally. The benefits of the programs could be compared considering how the future load profiles could be influenced and how the capacity supply plan is altered. The changes to the profile may be significant so that some capacity could be deferred or even avoided if there are many demand side programs implemented.

Supply side planning looks at the current electricity generation in use and explores the different options for capacity expansion. South Africa's electricity generation has been mostly coal-based and is likely to be the main technology for base-load capacity. There is scope to utilise other technologies for their specific benefit to the supply system such as clean coal technologies (CCT). Nuclear, gas (both imported Liquefied Natural Gas (LNG) and pipe line natural gas), hydro, imported and renewable energy resources are considered in the supply plan.

The energy model, MARKAL/TIMES, is used to determine the supply capacity expansion plan. The load profiles from each load type in each sector provide the demand data. TIMES is used as it has the functionality to represent each yearly load profile with sufficient intervals. TIMES is a partially dynamic model where the penetration for all demand and supply technologies is limited depending on their feasibility for implementation. All TIMES optimisation are for a minimisation of total system costs and environmental and social factors are not considered in the main model, but as additional scenarios, as there are no definite methods for their costing. The supply side data consists of the existing generation capacity and the future power station options for South Africa. Performance and cost data is used for each power station so that a reference expansion plan can be determined. The demand side is

modified with DSM and EE programs that could change the load profiles for specific end uses and sectors. Different scenarios can be modelled to see the effects on supply expansion plans for varying degrees of program penetrations. The results will show which demand side programs can be integrated into electricity planning for maximum cost benefit.

1.1 Literature review

Energy planners within electric utilities, government departments or research institutions have been exploring supply and demand options to meet consumers' energy needs. As new technologies become available, energy plans are adapted to make use of more efficient power station technology to meet growing energy demand. The characteristics of the energy demand also changes as end-use technology is developed for the relevant activity. Planners face the task of keeping updated on the choice of supply options and demand changes as well as their associated costs. The terminology least cost planning (LCP) was developed in the USA since the 1970's and is the task of cost optimisation of demand and supply options. The basic steps introduced by Roger Sant and Amory Lovins, are [Gellings et al. 1993]:

- Understanding how and where energy is consumed for final uses.
- Finding technology improvements in end-use efficiency.
- Analysing the costs and benefits for society.
- Use engineering and economic analysis to find the optimum level of efficiency to alleviate the costs of energy provision.

Integrated resource planning has evolved from least cost planning to include broader solutions and become more entwined in the energy planning process. Its differences to LCP include [Gellings et al. 1993]:

- Energy solutions from different perspectives such as the customer and utility
- Wider analysis of energy forms and their relation to present usage
- Range of various objectives each with defined time frames
- Decision processes based on economic, social and environmental benefits and costs.

The energy planner can gain confidence by adopting the IRP framework over the previous LCP methodology as there is increased flexibility in adapting to more situations.

IRP provide the linkages between supply options and the demand it serves so that risks and uncertainties are accounted for and the lowest cost of providing electricity can be obtained. The IRP methodology is particularly beneficial when there are vulnerabilities of energy supplies, environmental concerns and the need for energy efficiency so that less useful energy is wasted.

There is always a need for an effective IRP in opening up more energy service opportunities. Areas where resource use could be optimised fully with tariff restructuring, load management or efficient technology procurement could be located. Any investment in electricity provision requires comparison between additional generation capacity projects and customer's end use load and usage change programs. Assured capacity saving from DSM and EE programs can be compared as a "virtual power station" with its own specific costs and performance characteristics.

The investment in demand programs is spread over a wide area and its performance complicated due to the customer's diverse requirements. The evaluation of each program needs to take account of consumer reaction and related side effects in the energy industry. A comprehensive program should clarify where the potential for capacity savings exist. The potential can only be found with proper demand and supply analysis. The stages of IRP are a bottom-up structure, extending from the demand to the supply. Each stage in the IRP process uses data from the preceding stage. Data may need to be revised and stages repeated when new concerns or opportunities arise.

1.1.1 Integrated Resource Planning Stages

An IRP process can be developed with the following steps [Swisher et al 1997]. These steps are required in a plan but the scope of activities under each step will depend on the magnitudes of the loads that are considered.

1) Collection of consumer data

The current demand for electricity has to be analysed. End-use load profiles from actual measurements show consumption patterns. Statistical data and surveys provide

information on energy consumption and load types by categories of users. The information will require extrapolation to reflect the complete sectors in the plan.

2) Projections into the future

Projection of future demands is based on sectoral growths due to population, GDP or other external factors. Scenarios could be considered for high, medium or low growth. The validity of the growths is improved with an in-depth analysis of the electricity demand for each customer group.

3) Demand side options

Demand side programs of DSM and EE are explored based on the characteristics of the demand and the available technologies available. The program costs and their load change impacts are established.

4) Supply generation options

The costs and performance of the existing generation capacity must be determined. A supply expansion plan is designed based on the available energy resources and power generation technology. The expansion plan compares each option based on their full costs over the plant lifetime and external factors such as environmental considerations.

5) Design an integrated plan

The demand and supply options are compared in terms of their cost and benefits to the system. An optimal mix of options could be selected to meet specific levels of energy demands with the least costs to the system.

6) Implement least cost plan

Each demand and supply option chosen in the integrated plan would be implemented. The details of the projects need to be designed so that they operate as planned.

Resource planning using this approach will improve decision making on direct investments in energy supply and end-use technology. Each step in the process requires analysis that the most appropriate solution can be found to meet the future energy needs.

The links between the stages in the planning process is shown in figure 1-1.

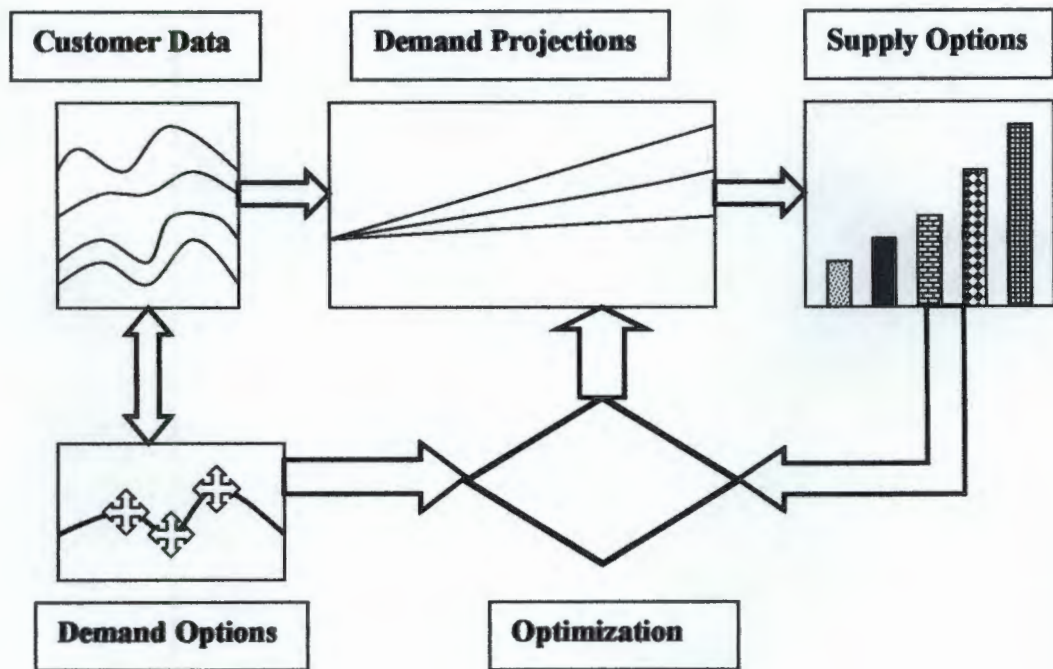


Figure 1-1 Flow of IRP process

The starting point is the breakdown of the demand that is currently using the electricity. The scope of the plan will determine the degree of analysis. The complexity of the analysis increases as more consumer loads are added. A national IRP would include all sectors of the economy and is therefore more cumbersome than the planning for a city although the planning process is similar. The availability of customer's electrical load data is limited and case studies of typical users may be needed. Less extrapolation is needed when a larger amount of actual loads are measured. It is beyond the scope of this project to measure actual loads and existing measurements were used.

Customer data is used to determine the future load requirements. Growth rates of electricity use are linked to external factors such as GDP growth. Scenarios could be built for different growth rates as a sensitivity study. A set of supply options are determined that could meet the demand projections. A supply side expansion plan is formulated to meet the predicted load by considering the available and alternative supply options that are most suitable.

There is a mix of supply options and load changing opportunities that could satisfy the different load projections. Demand side energy savings and load changing measures can

manipulate the load characteristics. Each demand resource needs to be selected based on the existing load and its characteristics. Programs costs and benefits are compared using actual electricity savings and capacity reductions. The most appropriate mix of demand and supply resources is selected by optimising the total costs to the system.

Load modifications would be extended into the projected demand to determine the long term effects of demand based programs. Possible effects to the load projection and the costs of DSM and EE programs ascertain their effectiveness. Demand resources compete with supply side option on a cost and performance basis. The total costs for the energy saved would have to be less than the cost of supplying that additional energy unit for such a savings intervention to be considered. Both the demand and supply resources are integrated into a least cost plan that meets the energy needs of the system.

The total investment cost of the integrated plan is affected by the rate of return for investors. Electricity pricing could change to recover costs of investment and consumer responses would provide feedback into the planning process. The process is reiterated on a continuous basis because new data and technology becomes available and because the demand changes in time. Shifts from large centralised supply to non-utility supply or distributed generation can also be researched using these planning stages.

1.1.2 Energy demand models

The level of energy service required for activities will depend on the technology that exists in the region. There are also socio-economic factors that influence the usage of energy such as the type industrial activity in the country and the degree of modernisation of population groups in using electricity to meet their needs. Energy requirements can be met by different means such as electricity or other forms. Bottom-up analysis is performed by quantifying the technological structure of energy conversion from the final use to the initial supply. Demand can be estimated from a physical description of an end-use technology and their performance characteristics. Bottom-up analysis can extend up the energy chain to incorporate more energy usages such as losses in distribution, transmission and electricity generation. Analysis of the complete chain provides a framework in which different scenarios can be compared in terms of the energy service provided and the effects on the electricity supply. The accuracy of the analysis is increased as the demand is disaggregated by type and region.

Energy data required for the end-use model can be broken down by the economic sector, activities, end-uses, relevance and magnitude. Data can be obtained by actual measurements of the energy used by each particular sector or end-use technology of interest by selecting a sample group from each sector. Data is often not completely accurate because of the dispersed energy usage by many end-use technologies and will need continual review. Energy demand is assessed using indicators such as the sales data of end-use equipment, comparison with other countries of a similar socio-economic standing or by questionnaires. Energy audits, surveys and billing data are also used to estimate the end-use breakdown.

The energy model for the use of electricity should be constructed to show how final services are dependent on electrical load usage. The model is extended to include more energy services. Simulations of future consumption will need inputs from growth indicators. Energy demand can be quantified using various models depending on the scale and accuracy needed in the plan. Models are based on econometric or end-use demand analysis [Swisher et al 1997]

1) An **econometric model** is based on energy prices and consumer income and is not quantitative but qualitative. It uses the Cobb-Douglas production function:

$$E = aY^{-\alpha}P^{-\beta}$$

Where: E = energy demand

a = coefficient

Y= income

P= energy price

α = income elasticity (%change in energy demand / %change in income (based on GDP)

β = price elasticity (%change in energy demand / %change in energy price)

The econometric model is useful for baseline or frozen efficiency (level of energy efficiency remains constant) energy demand projections but not for further projections where there are major changes in energy demand. The parameters a, α and β are calculated from past data and used to predict the future energy demands. This model is an aggregate way of understanding energy demand and its relations to income and price but the model loses its

predictive capabilities if there are changes in the structure of the demand for energy and consumer behaviour. The model can also be used for a particular sector's energy demand and the parameters would have to be specific to those activities.

2) An **end-use model** is data intensive and many forms of data collection are used to acquire the relevant data. Changes in technology or service can be specifically modelled and can be used for energy efficiency programs. The energy demand for a group or range of users is expressed as a sum of all the energy services that constitute the energy used.

$$E = \sum_{i=1}^{i=n} Q_i \times I_i$$

Where

E = Energy demand

Q_i = level of activity (quantity of service)

I_i = energy intensity (energy use per unit of service)

$$Q_i = N_i \times P_i \times M_i$$

Where

Q_i = Quantity of service i

N_i = Number of users for end-use i

P_i = penetration (units per user can be greater than 100%)

M_i = Magnitude, extent of use of service i

All energy services for each sector of an economy can be analysed to determine the total energy demand. Defining the variables for single customers or entire sectoral consumers allows the energy demand to be calculated for different situations. The quantity of service, Q , is the final use that is required such as total lumens for lighting or total hours for cooking. The parameter N is the number of households, commercial or industrial entities. The units for N can also be the amount of floor space. The parameter P is the share of customers using a particular appliance to meet an energy service such as the percentage of residential households using electrical lighting. The parameter M is the amount or level of service required such as lumens per square meter for lighting or hours of cooking time per residential household. The parameter I is the intensity of an end-use and has the units of watts or joules per energy service units. The units for the parameters need to be kept constant for a particular energy services but a different set of units can be used for other services.

Load profiles of electrical end-uses can be measured for specific loads or for a group of loads depending on the degree of analysis required. There is limited load profile measurement of specific loads as digital metering and recording is not common. Large electricity loads such as municipalities and industries do record their load profiles as a means of managing and monitoring their consumption and to verify their electricity bill with the utility.

There is a lack of information about national electricity use as end-use load profiles are not recorded on a constant basis. This report aims to determine a set of load profiles which represent the national use of electricity by end-use. The demand study uses a mixture of end-use and econometric methodology as demand growth depends on GDP but end-use load profiles reflect actual electricity consumption.

2 Electricity demand sectoral analysis

Electricity planning in South Africa considers all energy resource options and strategies to meet the growing needs of our economy. The low cost of electricity in South Africa, as a result of the large coal deposits and excess generation capacity, has broadened the use of electricity by all sectors. Each economic sector has specific electricity needs depending on their type of activity. A detailed demand study into how much electricity is used, at what times and by which customers, is required to explore the characteristics of electricity use. Integrated resource planning (IRP) considers both demand and supply side options in electricity service delivery. Electricity supply planning is enhanced through detailed demand analysis as future growths can be assessed more accurately. Demand side options such as demand side management (DSM) and energy efficiency (EE) measures need to be directed at a particular type of consumption pattern of certain electrical loads within a specific sector. This section investigates electricity usage of each sector by their electrical load sizes and yearly load profiles in the hope of finding areas where demand resources can be integrated into electricity planning. Each sector has specific electricity end-use requirements and growth potential in terms of energy usage.

2.1 Electricity use in South Africa

South Africa is a commodity driven economy because of the large mineral resources. The operations to extract minerals and process them have been made possible with large energy inputs. The use of electricity in the past has been dominated by minerals extraction and processing which are electricity intensive operations. Electricity intensity rose from 0.1 kWh/Rand in 1956 to 0.29 kWh/Rand in 1996 [NIRP 2003¹]. The electrical intensity has been decreasing since 1998 and this trend is expected to continue into the future as the economy shifts towards being more services orientated and achieving more beneficiation from minerals.

During the 1970's and 1980's, gold and diamond mining stimulated the electricity industry and large coal-fired power stations were built to cater for the increasing demand for minerals and metals. Decreasing quality of ore grades has resulted in lower gold production and more

¹ National Integrated Resource Plan 2003/2004 pg 8

energy is needed to extract and process the ore. As mine shafts get deeper, more energy is needed to lift the ore and to cool the deeper mining environment. International reduction in the gold price has caused some marginal mines to close in recent years and hence a decrease in the total energy consumption. Even though gold mining activities are decreasing, platinum mining has increased. South Africa has 70% of identified reserves of platinum group metals (PGM) [SA yearbook 2003] in 2000. Other mining activity includes diamond, coal, iron ore, chrome, titanium, manganese, vanadium, uranium, vermiculite, zinc, zirconium, copper, fluorspar, phosphate, lead, antimony, beach sands, tin and lime.

In addition to the extensive mining sector there is a large metal processing sector which uses a significant portion of generated electricity. Iron ore is extracted with the majority being exported. There is considerable iron production as well as ferrous alloys and steel operations [Coakley 2000]. Aluminium smelters dominate electricity consumption for the non-ferrous metals industry. South Africa has little bauxite reserves (the ore used to make aluminium). The cheap and abundant coal-based electricity resulting from over investment in capacity, has given the opportunity to develop aluminium processing by importing the ore, processing it locally and exporting the aluminium.

The wide variety of local metal and mineral resources provide inputs to diversified commodity operation. South Africa has large coal reserves and over 200 million tons are mined annually [Coakley 2000]. The coal is exported, used to generate electricity, provide industrial heat and as a feedstock to chemical and petrochemical processes. Sasol operates the world's largest coal-to-oil plants in addition to many downstream chemical processes producing a wide range of chemical based products and fuels that use electricity in the stages of conversion.

The population of South Africa was estimated at 45 million in 2002 [Statistics SA 2002]. There were almost 11 million households in 2002 of which 67.9% are electrified. Recent housing initiatives by the government, reconstruction and development program (RDP), has created the opportunity to uplift the poor through service delivery. Local industries have been stimulated through these programs by supplying building materials, electricity network

connections, water piping and sewerage systems. The electrification program has provided electricity to 4.375 million households from 1992 to 2002 [NER 2002²].

The electricity consumption for 2002 is categorised by each sector in table 2-1 below. Consumption statistics were collected from the National Electricity Regulator (NER) and the Department of Minerals and Energy (DME)³.

Sector	Demand (GWh)	% of total
Iron & steel	24784	13.4
Chemicals & petrochemicals	14089	7.6
Non ferrous metals	17398	9.4
Non metallic minerals	5676	3.1
Machinery	157	0.1
Mining & quarrying	32621	17.6
Food & tobacco	3594	1.9
Pulp paper & print	7501	4.1
Construction	562	0.3
Textiles & leather	562	0.3
Other industry	8841	4.8
Rail	6246	3.4
Public buildings	9781	5.3
Commercial buildings	8446	4.6
Residential urban	20630	11.2
Residential rural	1892	1.0
Residential township	3610	2.0
Residential electrification	4285	2.3
General services	9595	5.2
Farming	4644	2.5
Total Final Consumption	184814	100.0

Table 2-1 Electricity consumption by sector for 2002

Industry and mining consumed approximated 63% of electricity in 2002. Residential sectors consumed 16% of electricity in 2002 and commercial, public building and general services 15%.

² National Electricity Regulator's Electricity Supply Statistics 2002

³ Baseline study for the DME by Hughes et al 2002

2.2 Electricity demand study using load profiles

Total electricity consumption (GWh) statistics do not paint the full picture needed for analysing the national electrical load as electricity use is time dependant. As loads change, the supply has to instantly meet the demand. Electricity provision planning is improved with an in-depth understanding of the national load and its characteristics through enumerating each sector's electrical load operation. Representative load profiles of national electrical end-uses are needed to build a database.

The patterns of electricity usage are specific to each sector. Analysis of how a sector uses electricity can be complex because of the many energy related activities within each economic sector. Investigation is therefore required into how loads within each sector are operated on a daily, weekly and yearly cycle. Each type of load operated has to be accounted for in order to build a complete representation of the South African electricity demand. A load profile is a graph of the demand (Watts) plotted against time (hours) and shows how a load is operated over time. The area enveloped by the load profile curve is the electricity consumption (Watt.Hours).

End-use load profiles are used to determine the demand for a particular service.

Categorisation of activities included in each sector, simplifies the analysis as similar types of services can be grouped. The national electricity end-use database shows the patterns for each energy service within each sector and how they contribute to the total demand on the system. Analysis in this way is useful in determining the correct type of supply capacity needed as generation supply capacities differ between base loads (continuous operation) and peak load (short duration operation). Demand based resources such as energy efficiency (EE) and demand side management (DSM) can only be included by investigating the way they can change specific load profiles.

Each electrical load's operation is calculated for every sector. The end-use load composition for each sector by load type such as heating and motive power is determined so that the annual electricity consumption can be attributed to each load type. Load profiles for each load are collected to build a database of electricity use for South Africa. Load profile data gathered from municipalities, industry and Eskom are used to build the database. The bulk of the data was obtained from the Eskom DSM department. The data includes 3 weekly load

profiles (March, June and September) for individual loads for most sectors. Profiles for March represent typical summer profiles and profiles for June typical winter profiles. The profiles for the two selected months represent typical seasons as they are not the minimum or maximum consumption periods but close to average seasonal profiles. Availability to more data could improve accuracy about seasonal variation. In reality, the actual seasonal variation is not consistent but dependent on weather and activity.

Each sector's load is made up of end-use load profiles of the specific loads for that sector. Data was collected by measuring loads in selected industries, commercial building and residential homes. Although there is not much explanation as to the formulation of the data, it was the most readily available end-use electrical load information representative of the national electricity usage by customer categories. Verification of the data is difficult as loads were not measured directly. Actual measurement of sample customers loads is beyond the scope of this project. There is a lack of end-use load profiles as there is little measurement of specific loads. Better national representation of end-use load profiles could provide essential data for elaborate and strategic IRP.

Other sources of information were collected to attempt to verify some of the data from Eskom. The municipality data includes load profiles from Cape Town Municipality substations and load profiles from the planning division at Tshwane municipality. This data is included in appendix A. Data from AngloGold Ashanti and Mondi are compared to data from Eskom's DSM department. Accuracy in representing the sectors loads would be improved by doing energy audits at individual facilities and collecting energy information about what and when loads are used.

2.2.1 Electricity database of sectoral end-use load profiles

Each sector's electricity consumption is divided into the service provided from electrical loads. End-use categories are chosen so that loads providing a similar type of service can be grouped together. Table 2.2 shows the percentage electricity consumption split for all the final end-uses which represents the activities within every sector. There is always room for refining these figures as they represent a large number of activities within each sector and some loads may not have been included. The most detailed data of the end-uses were used to determine the load composition in each sector.

These figures have been derived mainly from data provided by the Eskom DSM department as it is the most detailed data available. The weekly consumption for typical summer and winter seasons are calculated from the load profiles and extrapolated to reflect a full year's electricity consumption. The contribution of each end-use load's annual electricity consumption is added to see the percentage end-uses within each sector.

Other sources were used to determine the electrical load usage by each sector and compared with Eskom data. Energy consumption data from all energy carriers [Solomon 2003] was combined with percentage energy requirements [Howells et al 2003] for each sector. It was assumed that other energy carriers besides electricity are used for process heating requirements and the remaining heating requirements are met by electricity. The other services can only be met with electricity. Generally, there was little difference between the derived end-use percentage requirements from energy data and those derived from the load profiles. Percentage requirements for the iron and steel and non-ferrous metal sectors used derived values as the Eskom data did not split the base metals sector into ferrous and non-ferrous.

The percentage requirements for electrical end-use loads in the industrial and mining sectors were compared with other values [Davison 96] and only slight variations were found thus giving further confidence in the representative data.

Source	Sector	Electrical End-Use percentage (%)								
		High Temperature Heat	Motive, Processing & Material handling	Pumping	Fans	Compressed Air	Industrial Cooling	Heating, Ventilation & Cooling	Lighting	Homes & Hostels
Derived	Iron and Steel	61.0	13.0	4.3	4.3	4.3		8.7	4.3	
Eskom	Chemical and Petrochemical	12.4	28.8	25.6	8.4	20.0		1.0	3.9	
Derived	Non-Ferrous Metals	80.2		3.1	5.2	4.2		4.2	3.1	
Eskom	Non-Metallic Minerals	23.2	40.4	8.7	9.1	7.0		0.7	11.0	
Eskom	Gold mining	2.2	38.0	16.6	7.9	19.6	7.0		4.4	4.3
Eskom	Platinum & other mining	3.2	49.6	12.1	6.8	13.7	5.7		5.1	3.8
Eskom	Food and Tobacco	18.6	28.9	12.5	5.7		22.4	0.9	11.0	
Eskom	Paper Pulp and Print	31.4	48.6					1.5	18.5	
Eskom	Other manufacturing	36.0	28.8	10.3	4.3	8.9		2.0	9.8	
Eskom	Agriculture	4.0	26.3	28.0	1.0		9.0	4.3	5.0	22.5
Eskom	Commercial	15.9		0.4	11.5	10.3		26.5	31.3	4.0
		Other (TV, Washing Machine, Pool Pump, kettle, laundry, gate motor & other plug points)								
		Cooking	Water Heating	Space Heating	Lighting	Cooling				
Eskom	Residential Urban	7.9	43.7	8.1	12.7	11.7		15.8		
Eskom	Residential Township & rural	27.1	29.4	2.7	15.0	11.0		14.8		
Eskom	Residential Electrification	14.0	0.0	7.1	22.7	27.5		28.7		
		Water Supply & Waste Treatment				Buildings	Street Lighting			
SOE CT ⁴	General Services	11				39	50			
		Passenger	Freight							
Spoornet	Transport Rail	30	70							

Table 2-2 Electrical end-uses for each sector

The amount of electricity used to provide specific end-use services can now be calculated. Table 2.3 shows the amount of energy and the percentage of electricity used for each final energy service. All similar end-uses have been collected from each sector to show the

⁴ SOE CT is the State of Energy report for Cape Town and the end-use requirements for general services have been extrapolated to reflect the national sector.

national demand for electrical end-use services. Residential end-uses, besides lighting, are grouped separately due to the different technology needed for those service requirements.

<i>Electrical End-Use</i>	<i>Electricity consumption (GWh)</i>	<i>Percentage (%)</i>
Rail	6246	3.4
Residential Cooking	3731	2.0
Residential Cooling	4190	2.3
Residential Space Heating	2121	1.1
Residential Water Heating	10639	5.7
Residential Other (TV, Washing Machine, Pool Pump)	5310	2.9
Motive, Processing & Material Handling (MotPrc or MatPrc)	36338	19.6
Process Heating : High Temperature & Electrochemical (HITempHt or HtEicChm)	42751	23.1
Fans	6812	3.7
Pumping	13317	7.2
Industrial Cooling	3327	1.8
Compressed Air	11523	6.2
Heating, Ventilation & Cooling (HVAC)	8411	4.5
Lighting	22649	12.2
Homes & Hostels	3112	1.7
Buidings (services)	3744	2.0
Water Supply & Waste Treatment	1056	0.6

Table 2-3 Electricity consumption by end-use 2002

The service which used the most electricity is process heating. Residential cooking, space heating and water heating are also heating services and if they are included the total requirement for heating in 2002 was 32% of all electricity consumed. Motive service is the second most demanding use of electricity and accounted for 19.6% of all electricity in 2002. Motors are also used for fans, pumps, HVAC⁵ and to drive compressors for compressed air and cooling with refrigerant gasses. The total electricity use by motors is 45.4 % of total electricity consumption in 2002, assuming that all the electricity for the mentioned services is provided by motors. There may also be further contributions to motor electricity consumption by including other residential loads and water supply and waste treatment.

⁵ HVAC systems use motors totally except where an electrical element is used for heating instead of a heat pump.

2.2.2 Methodology for representing national electricity load profiles

A database of the electricity demand is compiled where each load's hourly performance is accounted for. Each type of load is categorised for each sector and their annual electricity consumption quantified. The patterns of how loads operate were provided by Eskom's DSM department and the data is in the form of weekly load profiles for each load for 3 different seasons. Each load profile is grouped with similar services within a sector and the load profiles for other sectors not included are adapted from the available data. The typical winter weekly load profiles for each load within each sector are used to derive per-unit profile by normalising each profile (dividing each value by the maximum peak) and shown in Appendix B. The per-unit profiles show how the patterns of electrical load use within each sector changes over a week. The set of profiles show similarities between some end-use loads within a sector or with similar loads for different sectors. Profile shapes have not been individually verified as this would require extensive load measurement from many sectoral activities over long time periods. This electrical end-use database is a first attempt at ascertaining how all types of electrical loads are operated and the database can be updated if further measurements reflect different patterns.

Each spreadsheet is designed to show the hourly demand from a type of electrical end-use over the entire year. Spreadsheets are initially arranged within similar sectors but could be grouped by similar end-use activity. The process of building the electrical end-use spreadsheets, representative of all sectoral electricity usage throughout South Africa, is shown in the steps and in figure 2-1.

- 1) The per-unit shape for each specific load type in each sector is calculated from Eskom data. A per-unit profile is obtained by normalising every value in the profile by the maximum peak. The load operation is described by a weekly per-unit load profile where the peak demand fluctuates every hour. A typical summer and typical winter profile is adapted to other seasons. The load profile, L_p , contains a set of values normalised to 1 that represent the electrical demand for that load for every hour of the week.
- 2) The changes in the shape of the profile are applied to 5 seasons of the year by averaging the profiles to an intermediate season (between summer and winter) and averaging to a summer-intermediate season and winter-intermediate season by

averaging the profile between the intermediate season profile and summer and winter season profiles respectively.

The table below shows how the year is divided with respect to the shape of the load profiles.

Months	Season category
January	Summer
February	Summer
March	Summer
April	Summer intermediate
May	Winter intermediate
June	Winter
July	Winter
August	Winter
September	Winter intermediate
October	Intermediate
November	Summer intermediate
December	Summer

Table 2-4 Season categories for shape of load profiles.

- 3) Each profile is then normalised so there are 5 per-unit load profiles representing the full year. Each seasonal per unit load profile is allocated to the months of the year and a per-unit yearly profile with 8760 values is formed. Public holidays are included by assuming that they have the same load profile shape as a Sunday. There are 12 weekday public holidays included in each yearly profile. It is assumed that there is no difference in the per unit shape of the profile between seasons although there will be a magnitude difference. The seasonal magnitude difference will be included in the next step.
- 4) The yearly variation, Y_v , (seasonal fluctuation) is calculated by summing the difference in energy consumption of each load type from a July week to March and September weeks. Actual timing and magnitude of minimum and maximum electricity usage by each sector was not provided from Eskom and was assumed to be the same as the seasonal weeks. In the model there is no difference in weekly load profiles within the same month of the year although in reality each week may be different. A full yearly profile is derived by averaging the values between the given months and the other months. In the electricity usage representation, a significant magnitude change will occur in shape of a load profile as there is a transition to a new month. The transition could be made smoother by averaging each week not each

month but as there is already uncertainty in the occurrence of minimums and maximums, only the variation between months was used. Each end-use has its own yearly variation, represented as a percentage of full-load, as to how that load is utilised at different months of the year. The yearly variations for all the loads within all sectors are shown in appendix C.

- 5) The amount of energy (GWh) used by each sector is derived from statistical information [Hughes 2002] [NER 2002] and the data for the year 2002 was used as it is the most recent information available.
- 6) Each sector's electricity consumption is split into the actual end-uses that use the energy units. The make-up of each sector load is derived from Eskom information by summing up the demand for each week and season by end-use and using weighted averages (seasons are of different lengths) to reflect the percentage usage split for the year. The electrical end-uses split for each sector is verified from other sources as explained previously. The yearly usage (GWh) of each type of load is calculated from the annual consumption and end-uses percentage split for each sector.
- 7) An annual hourly profile, YP, can now be built for each end-use in each sector by the weekly per-unit shape being adjusted by the seasonal variation and its magnitude, M, increased until the sum of the demand (GW) for all hours of the year add up to the yearly usage of that particular use. Each hour of the year's actual demand is calculated using the equation below.

$$Yp(h) = M \times Yv(h) \times Lp(h)$$

- 8) The yearly load profile for all electrical end-uses in each sector is found using steps 1-7 in separate spreadsheets. The sectoral yearly load profiles for 2002 are shown in Appendix C. A total national demand profile can be calculated by staggering each sector profile on top of each other.
- 9) Additional years can be calculated by projecting the electricity consumption and selecting the new peak that will shift the yearly profile to match the total consumption. Each load can be calculated individually which is necessary to model the effects of energy efficiency, demand side management or other load modifications.

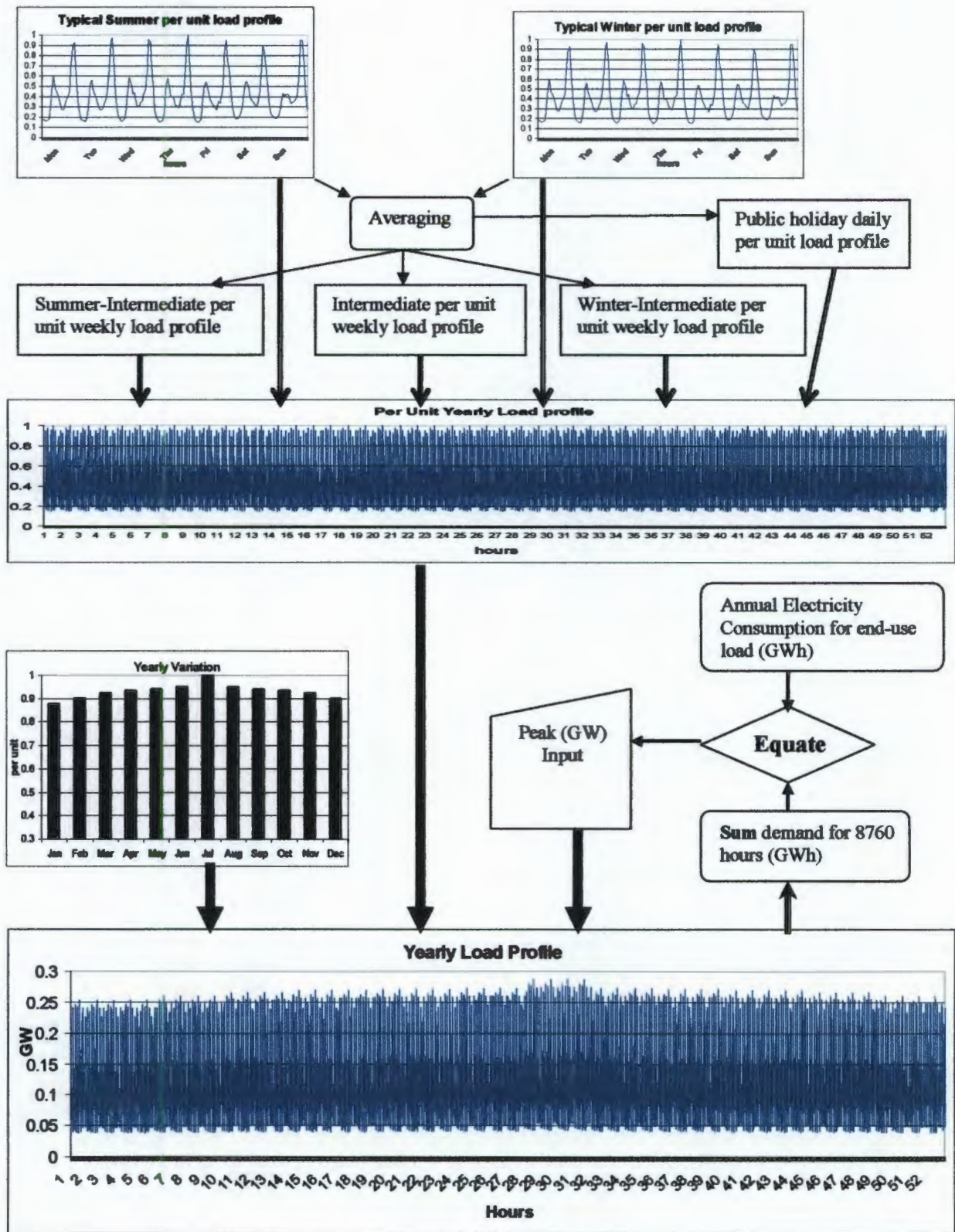


Figure 2-1 Procedure for compiling each yearly load profile

The task of representing all electrical end-uses in South Africa is massive and inaccuracies are present at every step although the representation is adequate for medium to long-term energy planning. The accuracy can be improved as more data is available and will possibly modify the representative profiles, yearly variations and electricity consumption values. The approach to use winter and summer typical load profiles uses less collected data but more extrapolation is needed to represent every week. A yearly variation by month can be modified to vary by each week for a smoother yearly profile.

Each week's profile is consistent within a month as the same average weekly profile is used for all weeks in a month. The actual peak day load profile on the entire electricity network is not represented and the month where the peak occurs contains the average peak profile. The actual peak can be 10% higher than the average peak and possibly only occurs for a single day within the season. Electricity planning in the short term will need to plan for such peak days but for medium and long term planning average peak daily profiles are more useful as the average yearly profile can be replicated for additional years by changing the final electricity consumption. An adequate representation has been chosen for the purposes of a national integrated resource plan but accuracy should be pursued with additional information from energy audits and increased measurements of electrical loads. Local planning for cities or distribution areas could adapt the load profiles to represent their activities. IRP methods can be replicated and modified for all levels of electricity planning, from single enterprises to local distributors and national supply. Regional electricity distributors would analyse the energy demands of all sectors and could plan a mix of supply and demand resources for continuous growth in service delivery.

2.3 Sector load profiles

A full yearly profile is compiled with electricity demand values every hour for each sector end use. The weekly shape is provided by the per unit load profiles included in Appendix B and the seasonal variations from the figures and tables in the previous section. Most recent electricity consumption figures are used to shift the entire yearly profile to fit the amount of energy consumed. A value is provided every hour and the sum of all the hourly values approximately equals the area under the profile which is the annual consumption. A single week is shown for each sector and the individual electrical end-use demand profiles are staggered to check the total sector pattern. The demand profiles are adapted for 2002 values. There are a total of 96 hourly year load profiles⁶ that reflect all electricity use in South Africa. The total system load factors or specific end-use load profiles can be built by selecting the appropriate loads. Each economic sector's load profile is shown for a winter week in 2002.

The load factor is an indication of how often a particular load is operated and is used to compare load profiles. The annual load factor is a measure of the variability of load operation to full load conditions and is calculated:

$$\text{Annual Load Factor} = \frac{\text{actual annual electricity consumption for load (GWh)}}{\{\text{peak electric demand of load during the year (GW)} * 8760 \text{ hours/year}\}}$$

The weekly load factor is a measure of how the load changes during a weekly cycle. Seasonal variations are not included as only a single week is analysed. The weekly load factor is calculated:

$$\text{Weekly Load Factor} = \frac{\text{electricity consumption by load for the week (GWh)}}{\{\text{peak electric demand of load during week (GW)} * 168 \text{ hours/week}\}}$$

⁶ There are 100 separate end-use profiles when the motive category for the commercial sector is disaggregated.

2.3.1 Iron and Steel

The South African iron and steel industry is highly developed and its electricity use is second only to mining activities. Crude steel production is dominated by Mittal-Iscor, who in 1998 accounted for 80% of production [Coakley 1999]. This sector also includes all the steel, stainless steel and ferroalloy production. Electricity use in this sector is split 65% for ferroalloys and 35% for steel [Eskom 2000]. The normal electricity intensity of steel production in South Africa is 600 kWh/ton [Davison 1996] where half the use is for production and half for rolling. The intensity for carbon steel is about 473 kWh/ton and 740 kWh/ton for stainless steel. Ferrochrome production uses 4.5 MWh/ton of electricity using direct reduction and 1.5 MWh/ton using a DC plasma process. The electricity intensity for ferromanganese is 3.4 MWh/ton and for ferrosilicon and silicon metal is 9.6 MWh/ton for 75% concentration and 3.5 MWh/ton for 25% concentration [Davison 1996].

The figure below shows the representative winter weekly load profile for total iron and steel industry in 2002. The total load profile is made up of all electrical end-use load profiles for the sector.

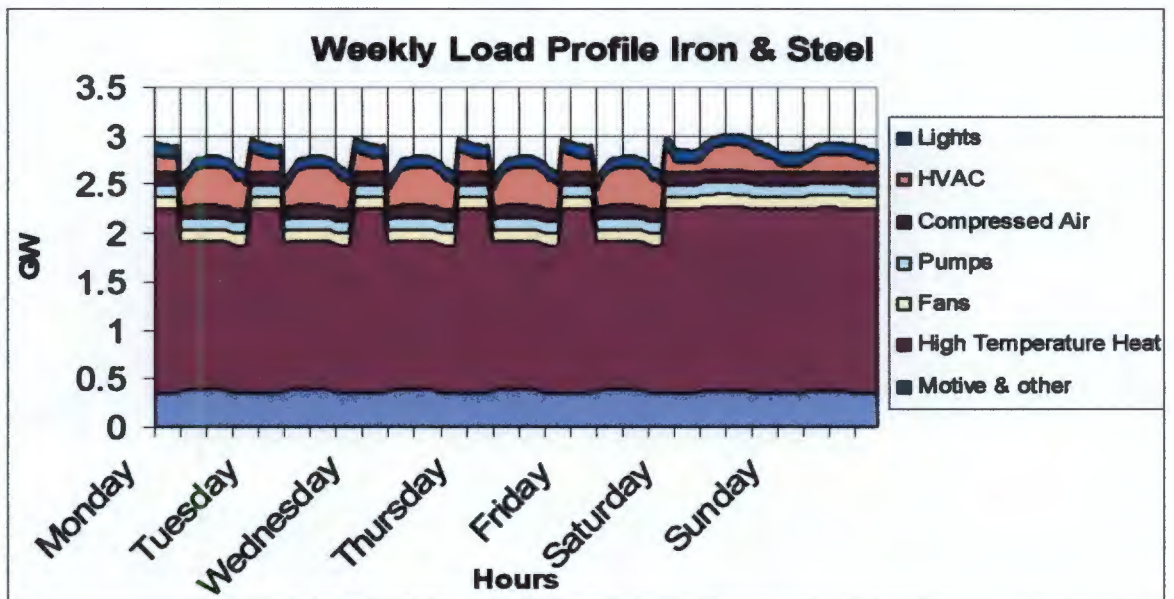


Figure 2-2 Iron and Steel industry weekly load profile 2002

The main usage of electricity in the iron and steel sector is high temperature heat. Most loads are operated at a constant level besides heating and HVAC. Electrical furnaces and other electric heating devices are operated fully (1.9 GW) every day from 22:00 to 6:00 and all

hours on weekends but at 80% of full load during the remaining hours. This is reflective of the time-of-use tariffs so that the lowest cost is obtained to provide that energy service. The peak demand time for all electricity use in the iron and steel sector of 3.02 GW occurs on Saturday at 13:00. The load factor for this sector is 0.937 and the weekly load factor is equal to the annual load factor because the level of operations is the same every week of the year.

2.3.2 Non-Ferrous Metals

The non-ferrous metals industry comprises mainly aluminium and titanium production. Aluminium production was 689 ktons in 1999 [SA yearbook 2003] mainly from the two smelting operations by Billiton Aluminium South Africa. The electricity intensity for aluminium production is 17.8 MWh/ton using a primary and secondary electrolytic process. Titanium production in South Africa was rated second globally in 1998 and exports third globally in the same year. The electricity split in the non-ferrous metals is 76% for aluminium and 24% for titanium. The electricity intensity for titanium dioxide slag production is 3.1 MWh/ton using a smelting operation with direct-current plasma arc [Davison 1996].

The figure below shows the representative winter weekly load profile for total non-ferrous metals industry in 2002.

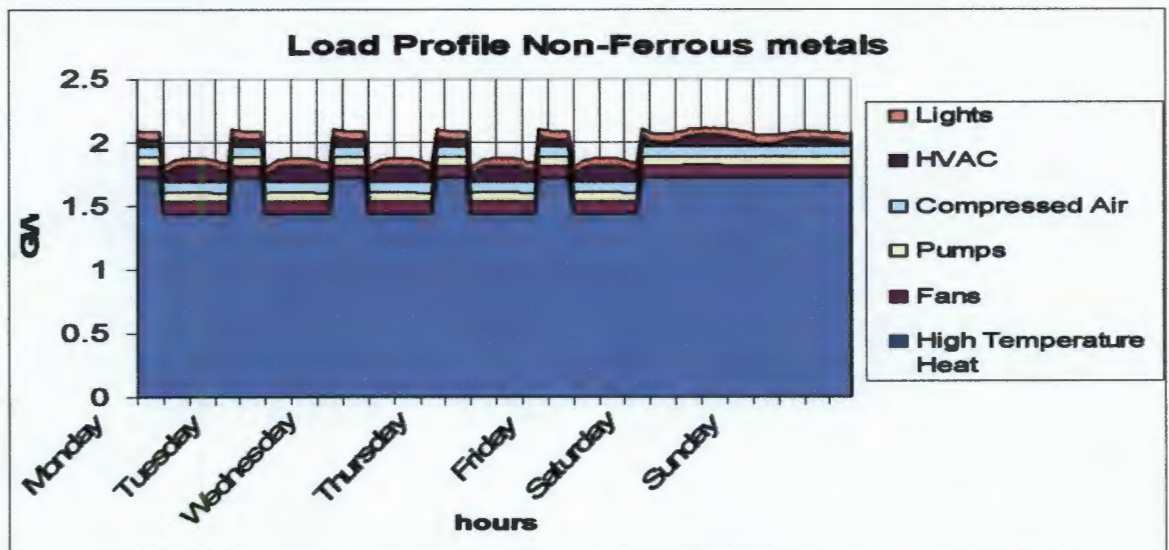


Figure 2-3 Non-ferrous metals industry weekly load profile 2002

The main load for non-ferrous metals production is the smelting operations for aluminium and titanium represented as high temperature heat in the profile. The heating load is operated at full capacity during the hours 22:00 and 6:00 and at approximately 80% capacity during the other times of the day. The peak demand time for all electricity use in the iron and steel sector of 2.12 GW that occurs on Saturday midday. During weekends, operations are at full capacity as the tariff agreements with the supplier provide the lowest electricity cost during the hours of 22:00 and 6:00 on weekdays and all hours over weekends. The load factor for this sector is 0.938 and the weekly load factor is equal to the annual load factor because the level of operations is the same every week of the year

2.3.3 Non-metallic minerals

South Africa has about 33 minerals which are mined locally in 497 mines and manufactured into products such as glass (silica), building materials (clay, stone, sand, ceramics, brick and cement) and refractory materials (mica and andalusite) [Coakley 1999]. There were approximately 1400 facilities contributing to the sector in 1996 [Statistics SA 2002]. A representative winter weekly load profile for total non-ferrous metals industry in 2002 is shown in the figure below.

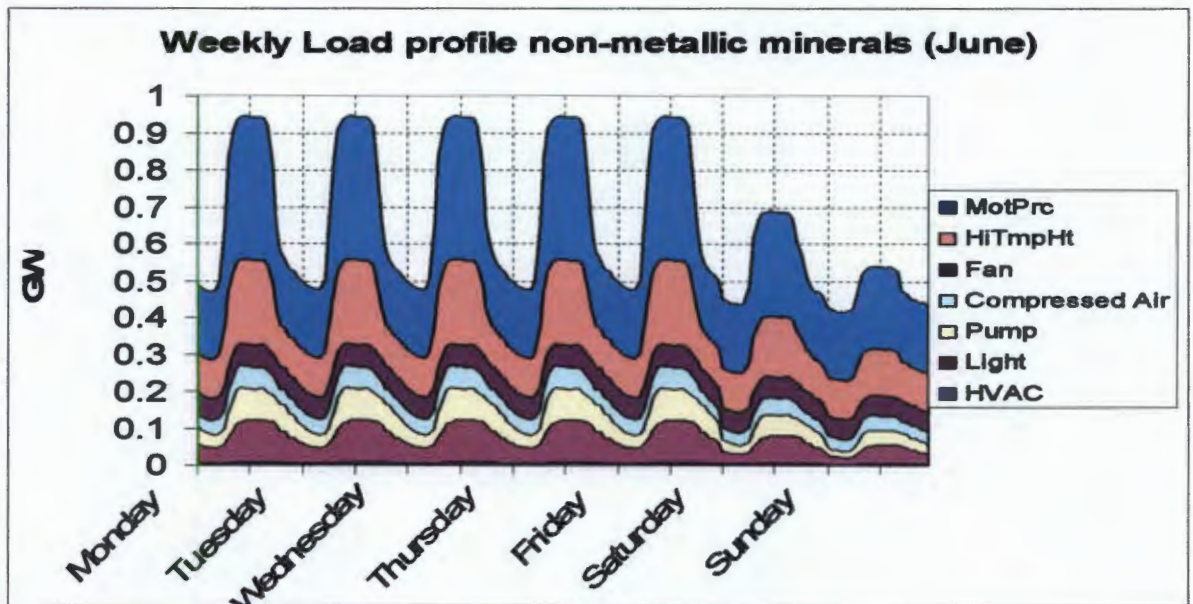


Figure 2-4 Non-metallic minerals industry weekly load profile 2002

Most the electrical loads in the non-metallic minerals industry follow a similar pattern where loads are utilised fully from 10:00 to 15:00 on weekdays. The profile shows a 2 hour build-up before and 2 hour taper off after these peak consumption hours and the minimum load is 50% full utilisation. This pattern is typical of light industry without large individual loads but with many smaller operations that operate during daytime hours. Electricity consumption is dominated by motive and material processing loads with heating being the second most utilized at approximately half the motive load. Electricity is used to crush and process minerals which are formed into products using heat processes. The remaining load is made up of fans, compressed air, pumps, lighting and a very small amount of HVAC. The pattern of electricity consumption for fans and compressors varies less than the other loads. The peak of 947MW occurs every weekday at 11:00. The weekly and annual load factor is 0.68 as there is no significant seasonal variation.

2.3.4 Chemicals and Petrochemicals

This sector includes industrial chemicals, refined petroleum products and other chemical products. There were approximately 1100 establishments in this sector in 1996 [Statistics SA 2002]. The weekly load profile, in the figure below, shows the patterns of electricity consumption for the chemicals industry.

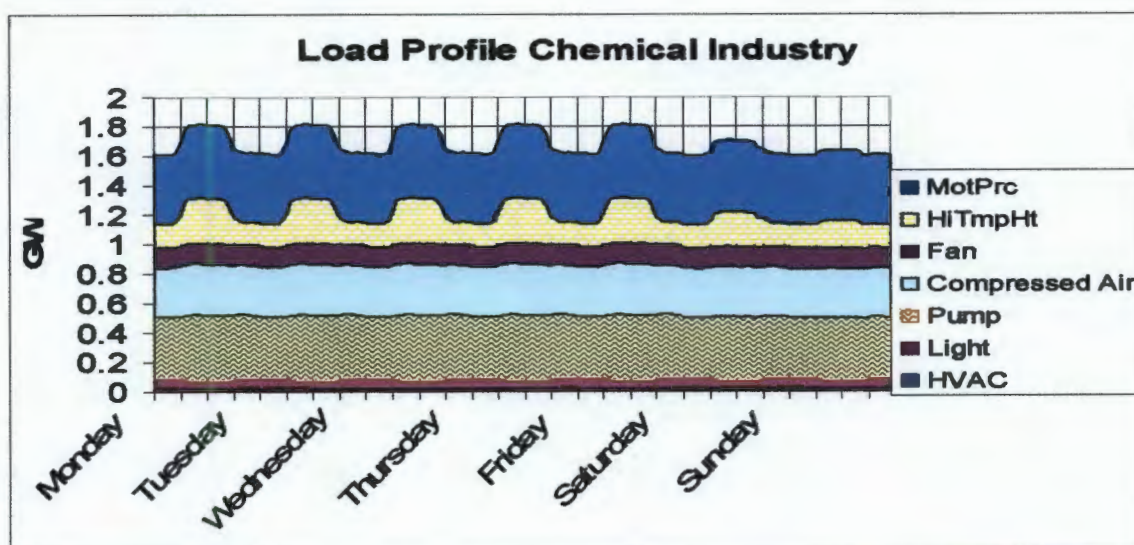


Figure 2-5 Chemicals industry weekly load profile 2002

The main loads in the chemicals industry are pumps, compressed air and motive and material processing. Their load profiles are flat with constant demands of 400MW, 300MW and 470MW respectively. High temperature heating loads fluctuate daily with a weekday flat peak of 300MW between 9:00 and 15:00. The remaining load is made up of fans, lights and a small contribution from HVAC. The combined peak of 1.824 GW occurs during September weekdays at 10:00. The constant demand of 1.6GW is maintained throughout the week but the peaks are reduced on weekend days. The annual load factor is 0.88 and the weekly load factor is 0.92 as there are seasonal variations in utilisation. The maximum load is reduced by 200MW during some months as is shown in Appendix C.

2.3.5 Food industry

This sector includes food, beverages and tobacco. Operations for this sector are production and preservation of meats, fish, fruit, vegetables, oils, fats and beverages as well as dairy and grain mill production such as starches and animal feed. There were approximately 2500 establishments in 1996 in this sector [Statistics SA 2002]. The winter load profile representing the national food industry is shown in the figure below.

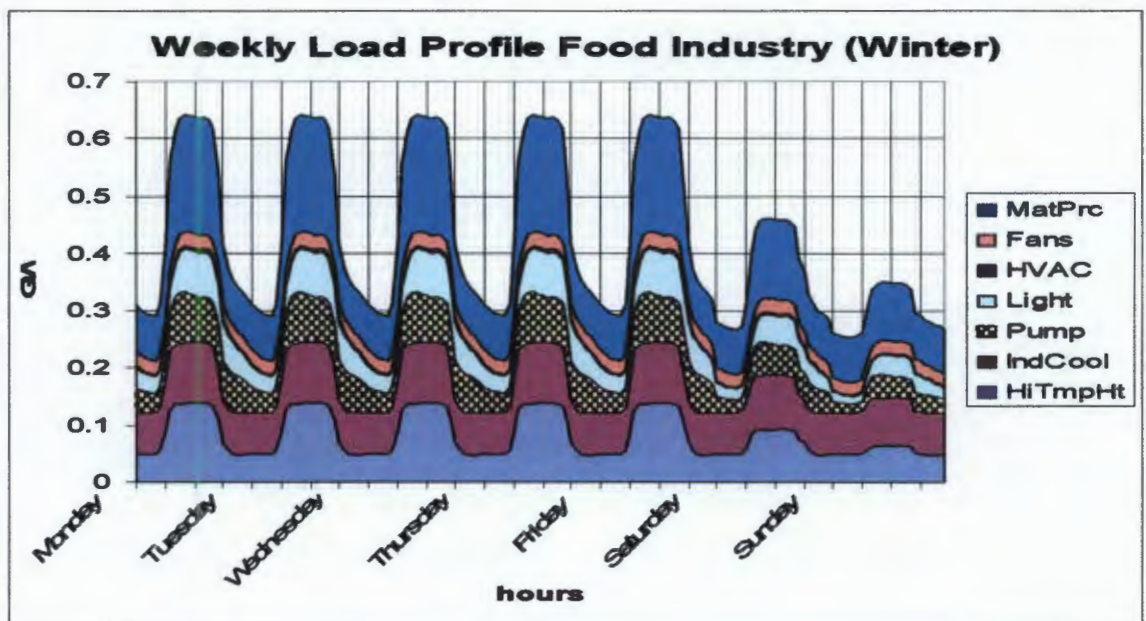


Figure 2-6 Food industry weekly load profile 2002

The utilisation of electricity in the food sector is spread over a few loads with motors for material processing being the largest consumer. The variability of the usage pattern is similar

(annual load factor of approximately 0.56) for most loads except fans (annual load factor of 0.91) and industrial cooling (annual load factor of 0.77) which are more constant than the other loads. The peak demand of 634 MW occurs in September on weekdays at 10:00. The annual load factor is 0.64 whilst the average weekly load factor is about 0.66 because of the small yearly variation.

2.3.6 Pulp, Paper and Print

This sector includes the manufacture of pulp, paper and paper products as well as printing and publishing. In 1996 there were 2500 facilities with operations falling into this sector [Statistics SA 2002]. There are large pulping and paper industries that have a very constant load. Local electricity generation is possible from the waste material of the pulping and paper processing. Mondi operates large pulp and paper facilities with production of boards (liner), and the following load profile is the per unit pattern of electricity use [Mondi].

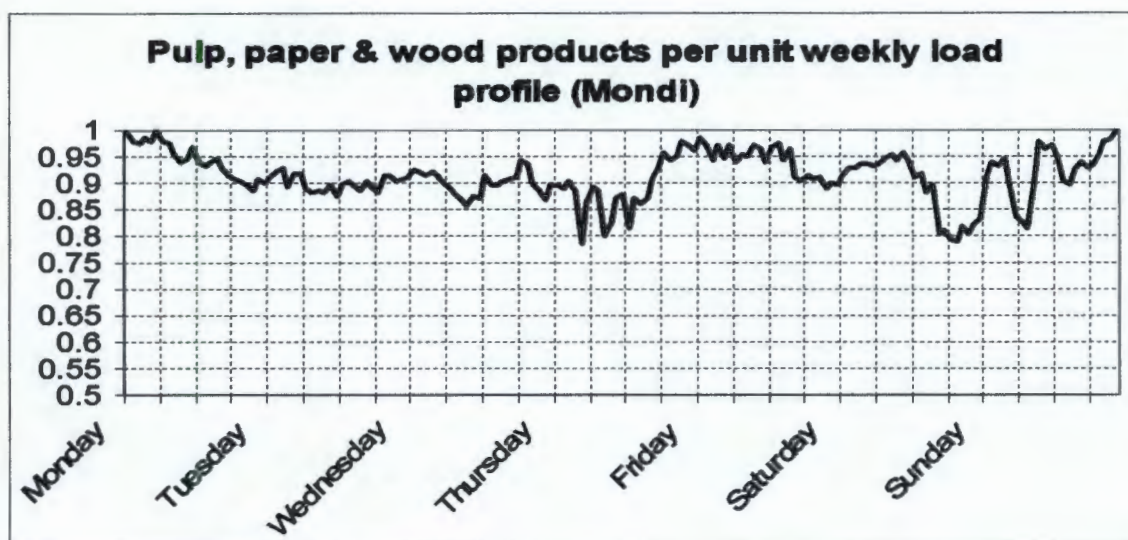


Figure 2-7 Mondi per unit electricity load profile

The electricity consumption is fairly constant and the weekly load factor is 0.91. Summer and winter load profiles are the same in shape and magnitude as there is sufficient insulation for heat processes. Electricity consumption patterns for the rest of activities in this sector change the load usage shape as there are many smaller enterprises that follow daylight working hours. The end-use load profile representative of the entire sector is shown below.

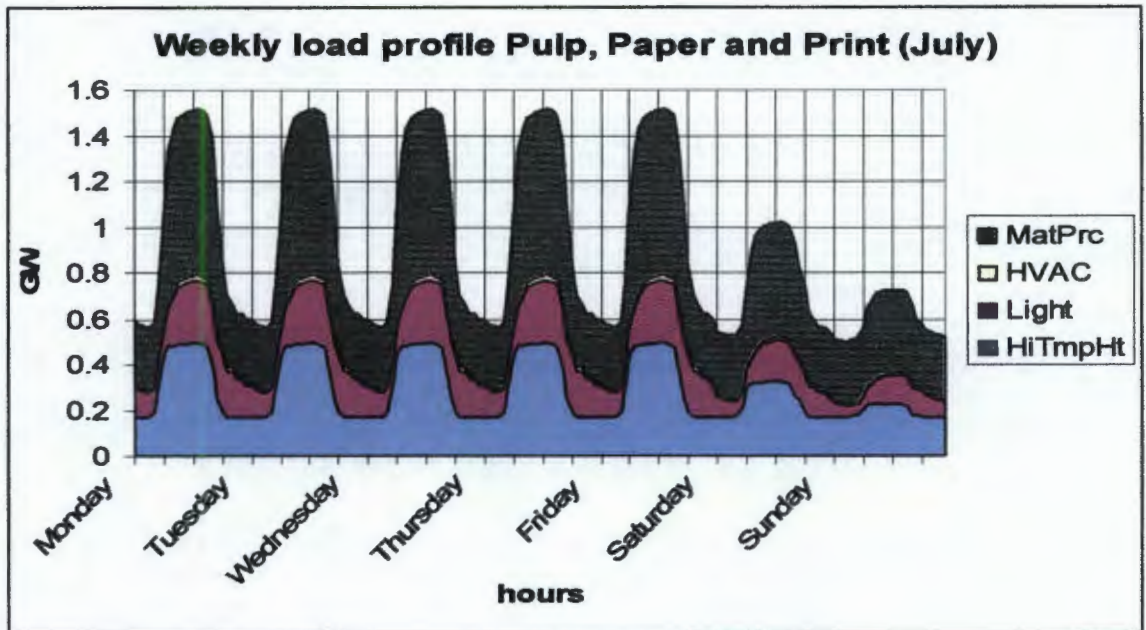


Figure 2-8 Pulp, paper and printing industry weekly load profile 2002

Main electricity consuming devices in the pulp, paper and print sector are motors used for material processing. The usage pattern has a daily peak between 6:00 and 18:00 with the maximum yearly peak of 1.157 GW occurring during weekdays at 13:00 in July. The weekly load factor is 0.57 whilst the annual load factor is 0.56 due to the slight seasonal variation of electricity consumption. The discrepancy with the load profile for Mondi is expected as the sector comprises large and small scale activities. Large factories, with bulk electricity supply tariffs, have more constant load profiles than smaller sized activities with multiple electrical load applications.

2.3.7 Other Manufacturing sector

The rest of the manufacturing industry is included in the other manufacturing sector.

Activities in this sector include

- Spinning, weaving and finishing of textiles
- Manufacturing of textile and fabric products
- Making wearing apparel
- Leather goods and footwear
- Wood products and furniture
- Fabricated metal products

- Machinery, electrical machinery and appliances
- Radio, television and communication devices
- Motor vehicle, parts, accessories and transport equipment
- Electronic equipment
- Plastic and rubber products

There were approximately 18500 manufacturing facilities in 1996 that are incorporated in the other manufacturing sector. The total load profile, consisting of each end-use type, is shown for a typical summer week in February.

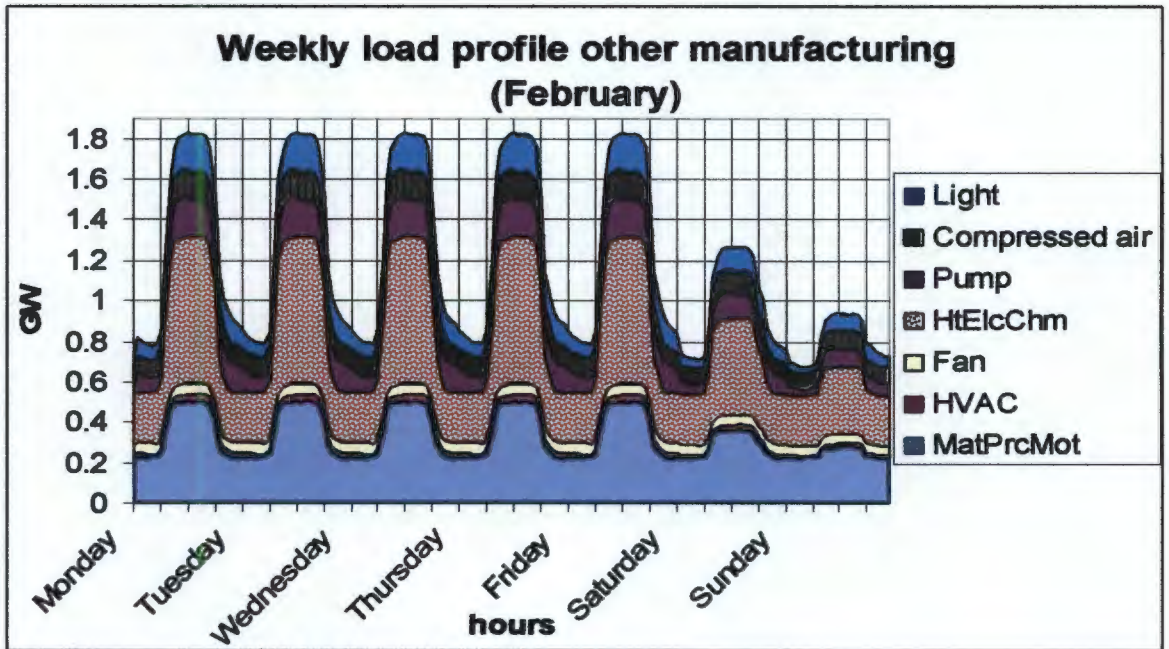


Figure 2-9 Other manufacturing weekly load profile 2002

There are a wide range of electrical end-use loads in other manufacturing because of the diversity of manufacturing activities. The largest electricity usage is for heating and electrochemical processes. There is an overall daily peak, as shown in the figure above, from 10:00 to 17:00 indicative of the work times for small manufacturing concerns. There is a constant load of 0.8 GW at all times due to some operations being on a 24 hour cycle. The level of electricity use increases rapidly from 6:00 to the peak value of 1.83 GW (peak month is February) and decreases more gradually to the constant value. There is a large decrease in the peak demand on weekend days whilst only a slight decrease in the constant demand from weekdays as there are many operations on a 7 day cycle. The annual load factor is 0.63 and

the yearly profile is mostly constant with a reduction of 4% in peak demand from February to July.

The other manufacturing sector consists of a large number of industrial activities that can be considered light industrial loads. Municipalities provide the electricity to many of these enterprises as they operate within their distribution area. Data from Cape Town municipality was used to compile a representative per unit load profile for light industrial electrical loads as shown in appendix A. The weekly load factor for light industrial electric loads is 0.5 which is lower than the profiles used for the other manufacturing sector as there are more constant loads represented in the sectoral load profile.

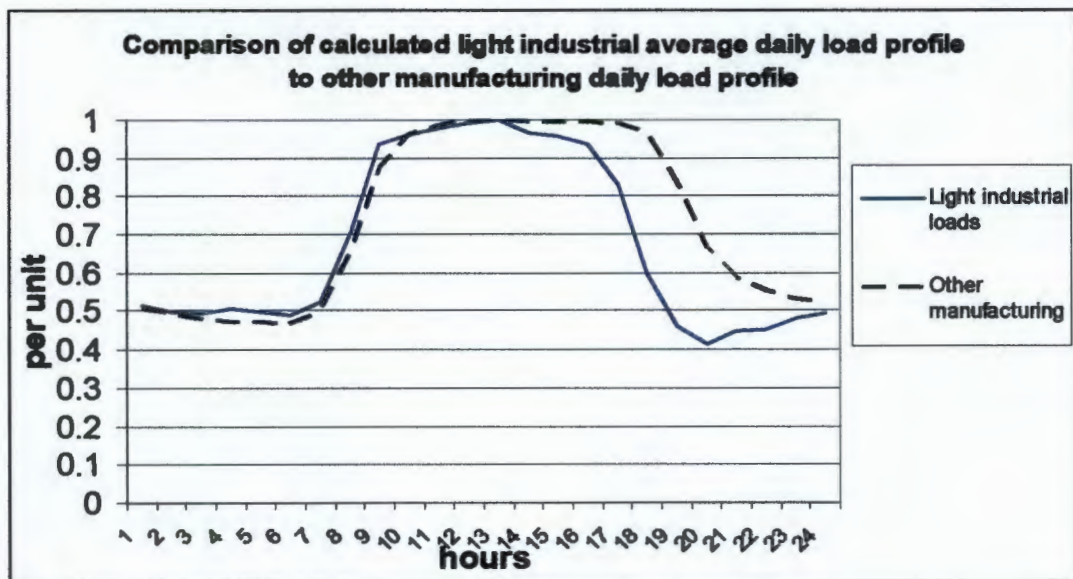


Figure 2-10 Light industrial and other manufacturing average daily load profile comparison

Figure 2-10 shows a comparison between then per unit average daily load profiles for industrial activity. The main difference is early reduction of the light industrial demand from 17:00 whereas the other manufacturing is reduced after 19:00. This may be due to different work patterns, misrepresentation of industries for comparison or loss of data during calculation of the light industrial load profile as a filter is used to remove residential components (morning and evening peaks). Due to the increased details of electrical end-uses in the other manufacturing data over the municipal industrial load data, the demand data base includes the other manufacturing data to be representative of the sector.

2.3.8 Gold Mining

Gold mining has been an essential growth driver of the South African economy in the past. Technology is highly developed to extract gold from the deepest mines in the world. Even though ore grades are decreasing as the most exploitable reserves are mined, South Africa is still the world's largest gold produced with a 19% share in 1998 [Coakley 1999]. The calculated electricity intensity in 1994 was 38 GWh/ton of produced gold and in 2001 was 47 GWh/ton as there was a significant decrease in production output from 580 tons in 1994 to 370 tons in 2001 [Statistics SA 2002].

The industry has been subject to falling gold prices which led to a continual search to reduce operating costs. One of these methods has been to run electricity intensive process during off-peak times. Negotiated time-of-use and real time contracts have been agreed upon with the supplier to achieve the lowest electricity prices possible. The two largest mining companies operating in South Africa are AngloGold Ashanti LTD and Gold Fields LTD. Two weeks (summer and winter) of measured values were provided from Great Nologwa, Kopanang and Tau Lekoa mines and include some extraction of uranium which is a by-product of gold mining. The load profile below shows the pattern of AngloGold Ashanti's mining activities for a winter week in August 2003 [AngloGold Ashanti].

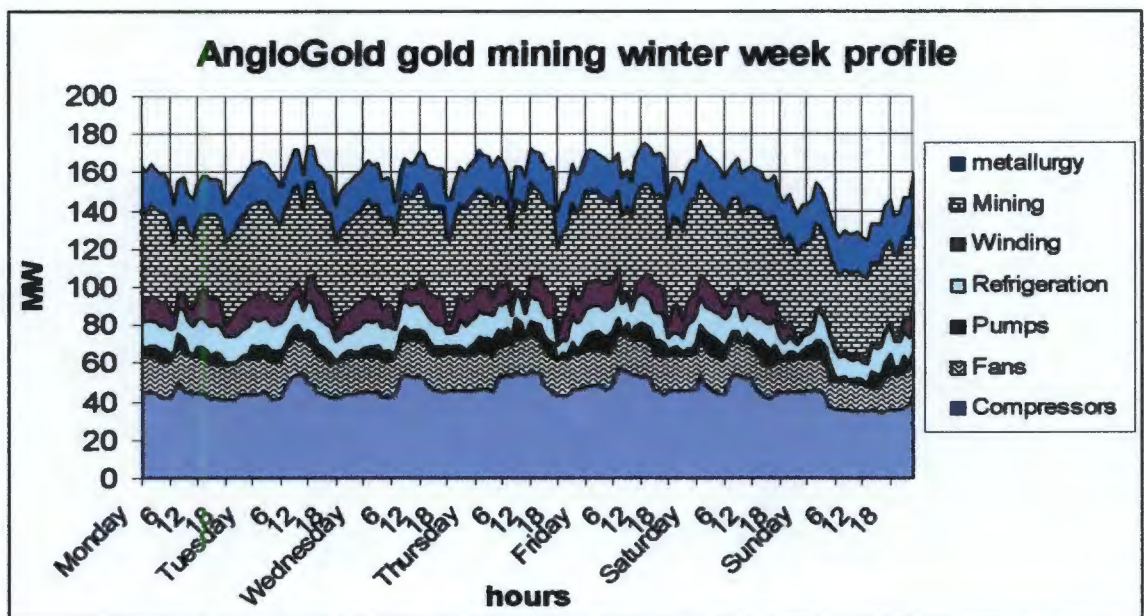


Figure 2-11 AngloGold Ashanti electricity end-use load profile winter week 2003

Generally, the peak demand time is between 1:00 and 6:00 am. The data is not completely separated into end uses as can be seen with the category mining. There a definite reduction in demand on weekends especially on Sunday. The weekly load factor is 0.89. Approximately 18% more electricity is consumed in summer and the annual load factor is therefore reduced to 0.75 using a monthly variation by averaging each month between summer and winter.

The following profiles were generated using the per unit profiles from Eskom DSM included in appendix B and represent the entire electricity demand for gold mining in South Africa. The winter reduction in demand is consistent with AngloGold Ashanti's data but the shape of the profile is different as the per-unit profile uses average profiles, not real data, and represents all gold mining activity. There are additional end use categories in the load profiles below for homes and hostels and lighting for the mines.

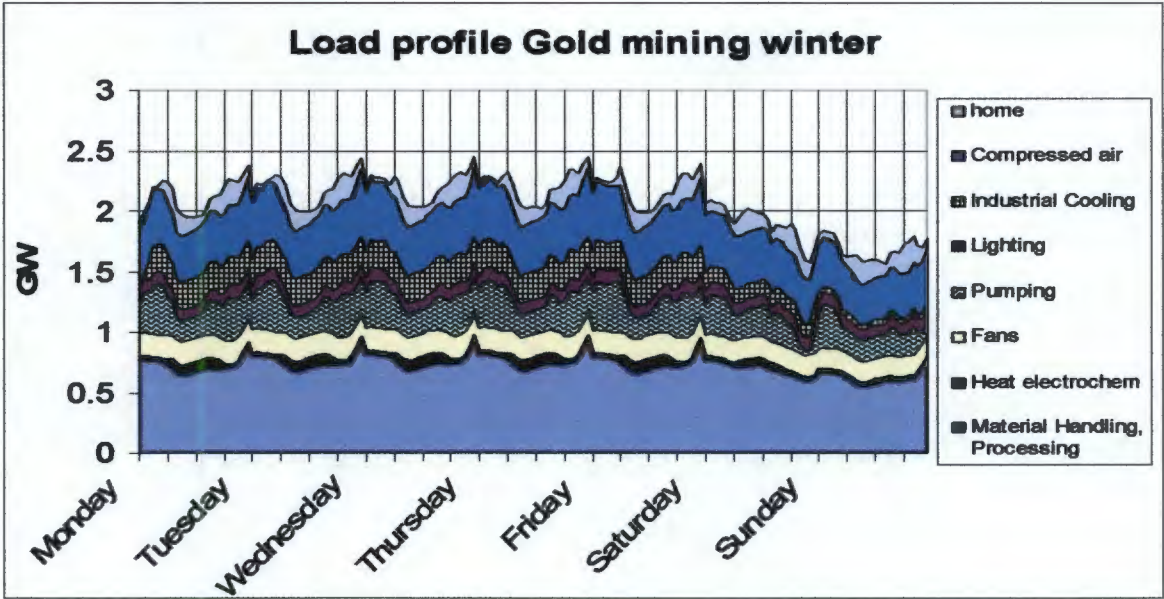


Figure 2-12 Gold mining weekly load profile winter 2002

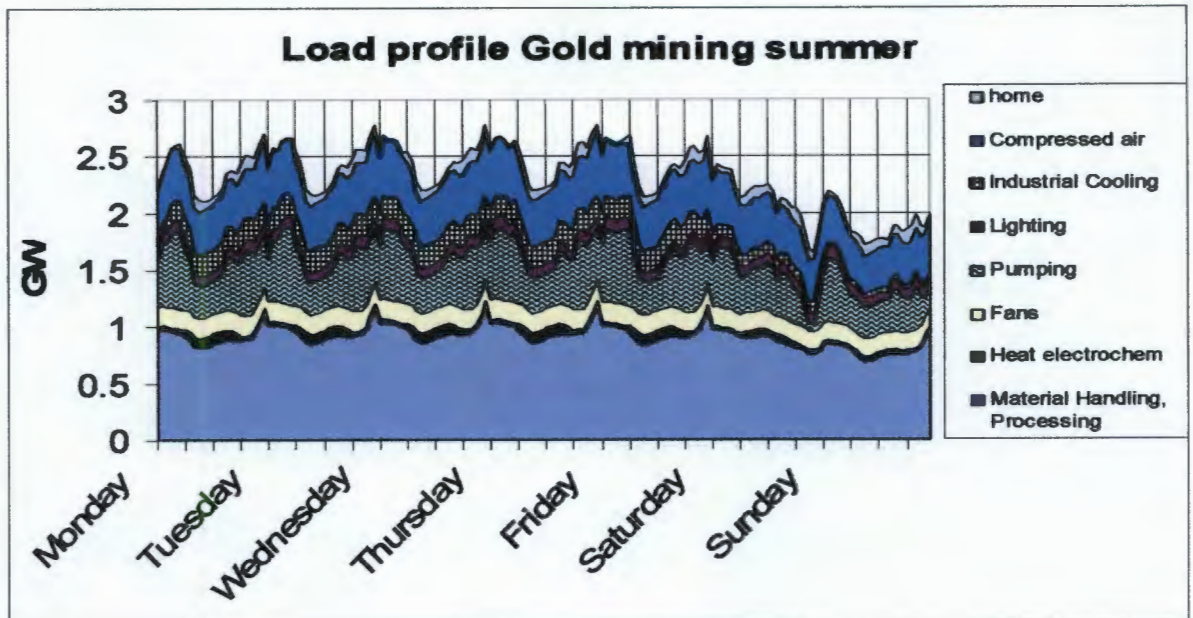


Figure 2-13 Gold mining weekly load profile winter 2002

The annual peak is 2.78 GW which occurs in summer weekdays at 23:00. The main electricity consuming devices are motors for hoisting, winding and processing of materials. The peak for the usage pattern of motors is on summer weekdays at 23:00. The second largest loads are pumps that have a daily peak demand at 6:00. The total maximum demand for gold mining occurs during summer weekdays between 22:00 and 6:00 which are considered off peak times for the national load. The load profile is very dependant on the tariff chosen. Many mines have changed tariffs from Nightsave to Megaflex [Gildenhuys 2005] and the profile shape would need to be modified to represent current electricity use in mines. The annual load factor is 0.8 and the weekly load factor for winter would be higher but the summer weekly load factor lower due to the increased electricity use in summer. Due to the lower temperatures in winter, less cooling is required for machines and the working environment.

2.3.9 Platinum and Other mining

Platinum mining consumes the most electricity after gold mining and there is a large amount of other mineral and metal mining which also consume electricity. Anglo Platinum is the world's largest PGM (platinum group metals, including palladium) producer from operations only in South Africa. National platinum production increased from 143 tons in 1991 to 229 tons in 2001 [Statistics SA 2002]. The most significant other mining in terms of electricity

consumption are coal, copper, diamond and other surface mining such as iron ore, chrome, manganese, fluorspar, phosphate and lead. The calculated electricity intensity for platinum is 28 GWh/ton and the intensity for coal is 12.8 kWh/ton as there are fewer electrical loads needed. The representative load profile for an average peak week for national platinum and other mining for 2002 is shown in the figure below.

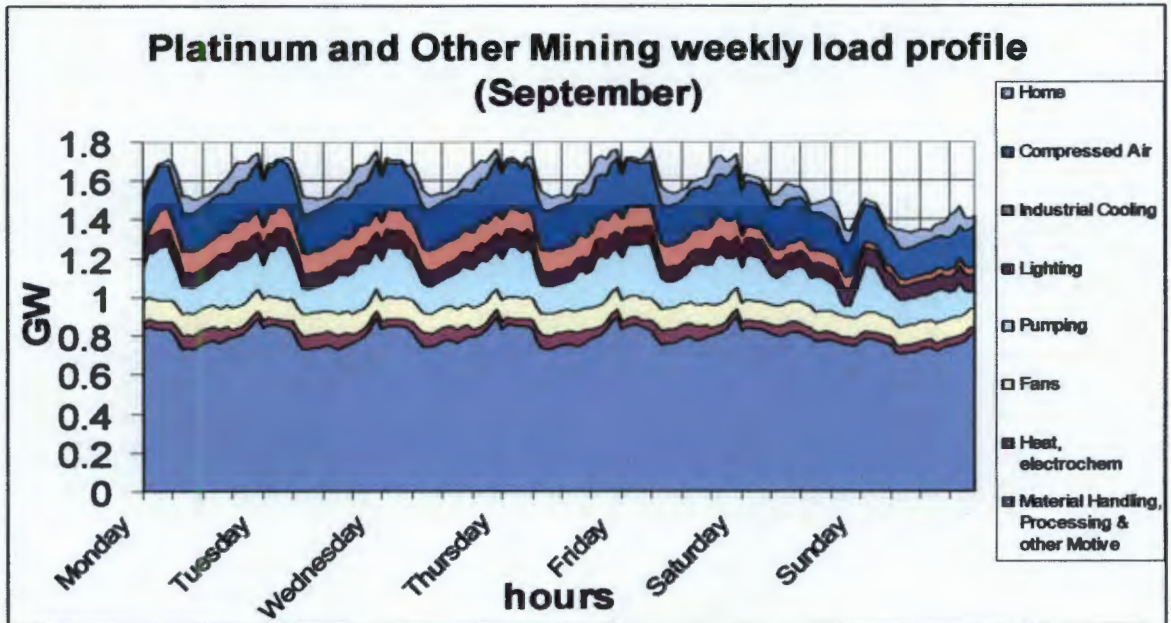


Figure 2-14 Platinum and other mining weekly load profile 2002

The main electrical loads are motors for material handling that have a nearly constant demand of 700MW throughout the year. The profile for motive loads peaks every weekday between the hours 23:00 and 6:00 and has an annual load factor of 0.82. Compresses air is used for drilling and other mining operation and its usage pattern varies more than motive power as its annual load profile is 0.75. Pumping consumes slightly less electricity than compressed air but has a higher peak as its annual load factor is 0.64. The maximum peak of 1.77 GW occurs during September weekdays at 23:00. The annual load factor for the total sector load profile is 0.84 and the percentage peak difference between the maximum peak demand (September) and the minimum peak demand (June) is 9%.

2.3.10 Commercial

South Africa is a large country with many commercial centres. The commercial sector includes business, trade and service activities such as [SIC 1993]:

- Wholesale and retail trade
- Repair to motor vehicles and appliances
- Hotels and restaurants
- Financial services , banks and insurance
- Real estate and business services (renting equipment, research and development and accounting and auditing)
- Central and local government activities (some building may be categorised under general services)
- Education
- Health services
- Social work and community services
- Entertainment, recreational, cultural and sport activities

The end-use load profile representing the national commercial sector is shown in the figure below. Motive end-use includes pumping, fans and other motive devices such as elevators and escalators in building.

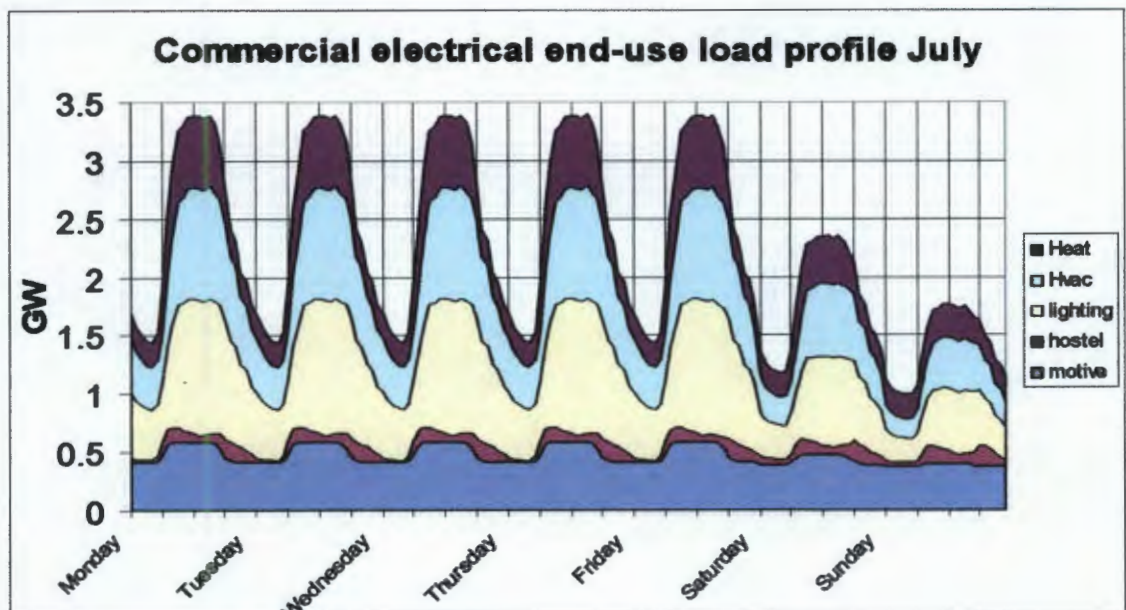


Figure 2-15 Commercial weekly load profile 2002

The main electric loads used by commerce and public services are lighting, heating, ventilation and cooling (HVAC) and motive power. Lighting and HVAC have similar usage patterns as their usage increases at 6:00 daily and reaches a peak at 9:00, where the usage is constant until 17:00. The usage then declines slowly to the minimum demand at 4:00. The annual load factors for lighting and HVAC are 0.54 and 0.57 respectively. Utilisation of motors is more constant with an annual load factor of 0.69. The total maximum peak of 3.42 GW occurs in June during weekdays at 12:00. The minimum peak occurs in March⁷ at the same daily hour and is 86% of the maximum peak. The total sector annual load factor is 0.61.

2.3.10.1 Comparison to municipality load profile

Commercial load profiles from municipalities are included in Appendix A. A typical commercial load profile is calculated from measured substation data from the Cape Town municipality. Various commercial load profiles for sub-sectors such as offices, education and governmental buildings are obtained from Tshwane municipality electricity planning department. A representative load profile can be compiled using a breakdown of the commercial activities into specific sub-sectors. The figure below shows a mostly commercial per unit load profile for Tshwane calculated using weighted contributions from the various commercial load profiles. The filtered commercial profile from Cape Town municipality measured substation data is also shown and an average taken between the two profiles to merge the two profiles. A winter and summer profile is shown.

⁷As noted earlier, it is assumed that the profiles for March (representing typical summer) are the minimum usage period and those for June (typical winter) are the maximum.

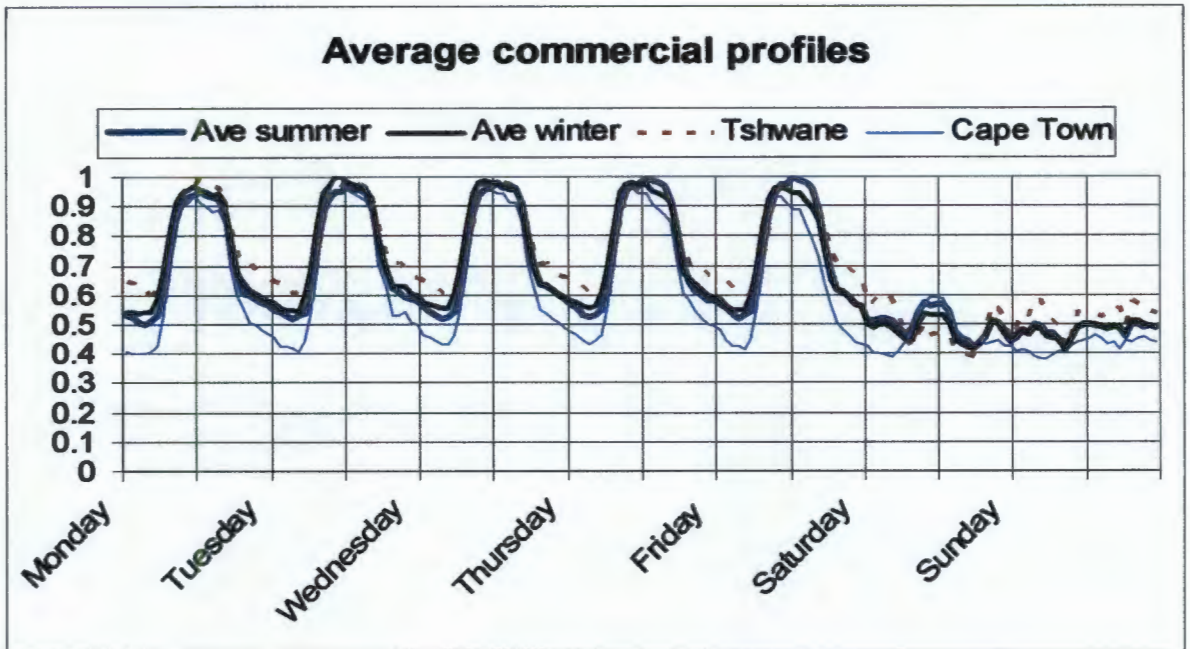


Figure 2-16 Comparison of average weekly per unit load profiles

The weekly load factor for the average summer profile is 0.66 and for winter weeks 0.67. The Cape Town commercial profile, with a 0.6 weekly load factor, is most similar to the representative profile used to build yearly end use load profiles. The weighting for the Tshwane load profile could be rearranged to represent a more balanced commercial sector as there are a few different profiles representing different commercial activity such as offices, businesses and educational institutions. The profile could be matched to the commercial profile shape from Eskom DSM department with larger contributions from offices and businesses. It is therefore possible to weight the contributions from the various activities within a sector in one region to represent other regions provided that the levels of activity are known.

2.3.11 General Services

The general services category comprises street lighting, water supply and waste treatment and buildings involved in municipal service delivery. The electrical use split for this sector uses information from Cape Town Municipality on service provision and is extrapolated to reflect the national situation. The percentage use is 50% for streetlights, 39% for building and 11% for bulk water supply and waste treatment [State of energy Cape Town 2003]. In reality

buildings may have a lower contribution as some local authority buildings are included in the commercial sector. The shape of the street lighting load was assumed to be the same as day/night hours for winter and summer and that there is zero consumption during daylight hours. The profile for buildings is assumed to follow a commercial profile shape and the profile for water supply to follow an industrial shape. The per unit weekly load profiles for each end-use are included in appendix B and the total sector's estimated weekly load profile for an average winter week is shown in the figure below.

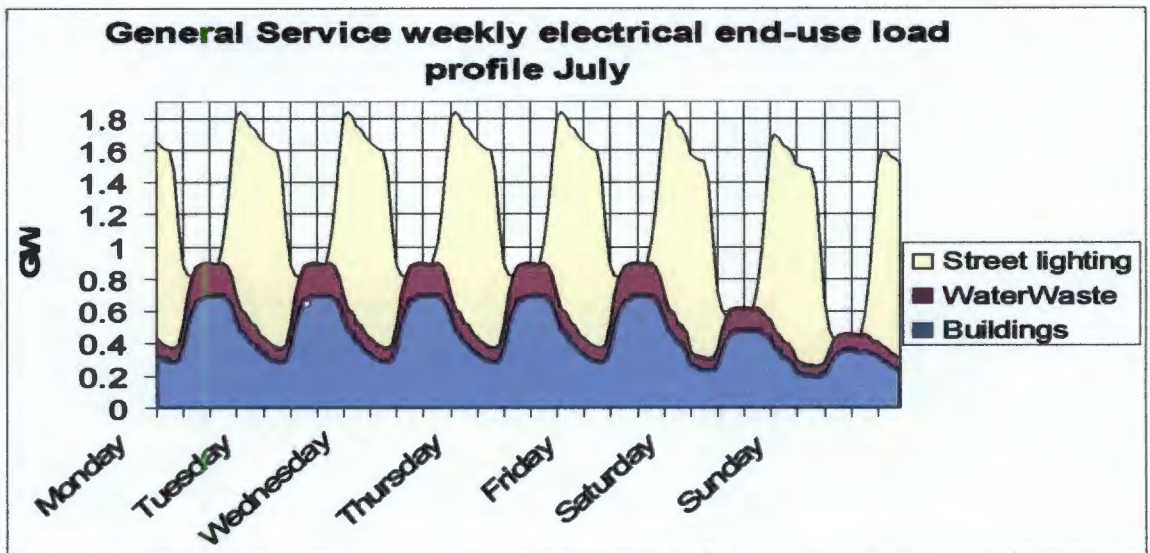


Figure 2-17 General services weekly load profile 2002

The total electrical load profile for a winter week is shown in the figure above. The most significant electrical usage by general service is street lighting with a peak of 1.25 GW on winter nights⁸ between 20:00 and 4:00 and an annual load factor of 0.44. The combined peak for the sector is 1.88 GW occurring at 19:00 during winter weekdays and the annual load factor 0.58. The peak demand decreases by 19% for days in March when the least demand occurs as March represents a typical summer period and less heating is required for buildings and street lighting operate for fewer hours compared with winter periods.

⁸ As winter nights are longer than summer nights, there will be more street lighting usage in winter. The decrease from winter to summer is represented by two more hours of usage in winter and a 16% decrease in the peak street lighting load.

2.3.12 Agriculture

This sector includes all agricultural activities such as commercial farming and small-scale farming on homesteads. The end-use load profile for a peak week is shown in the figure below.

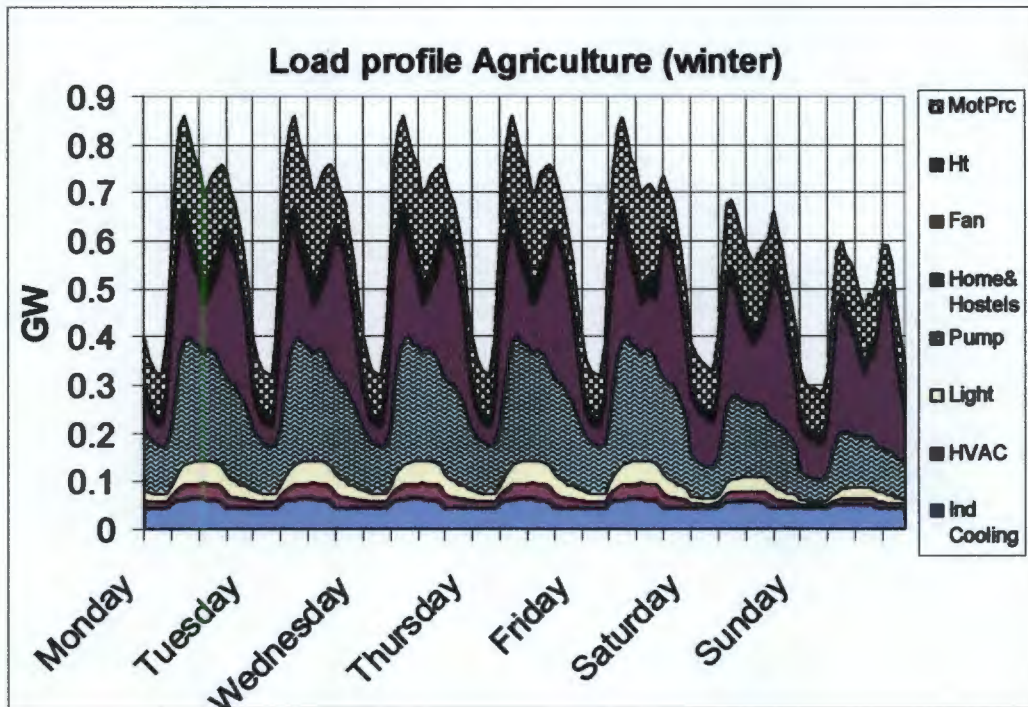


Figure 2-18 Agriculture weekly load profile 2002

The main consuming loads in terms of annual electricity (GWh) consumption are pumps, motors and homes and hostels. The homes and hostels peak is 300MW and is the largest individual load peak (Sunday 19:00 in July) because the load factor is 0.37, representative of a residential consumption pattern. Pumping loads have a daily morning peak at 9:00 of 262 MW and their annual load factor is 0.57. Motors used for material processing have a weekday flat peak between 8:00 and 16:00 of 225 MW and an annual load factor of 0.62. The maximum combined peak of 859 MW occurs in June on weekdays at 8:00 and the peak is reduced by 17% during times of minimum consumption in the month of March. The total annual load factor is 0.62.

2.3.12.1 Comparison to Tshwane municipality data

The load profiles for agricultural customers from Tshwane municipality, appendix A, also show a morning peak with reduced subsequent peaks. The Tshwane load profile has multiple daily peaks but of similar proportions to the agricultural profiles used. The weekly load factor used to represent the sector is 0.62 which is between the ranges of Tshwane agriculture load factors of 0.5 to 0.67. An average of the daily per unit load profile shows when the shape change occurs. More insight and accuracy is obtained by using more detailed load profiles for each end-use such as those from Eskom DSM department.

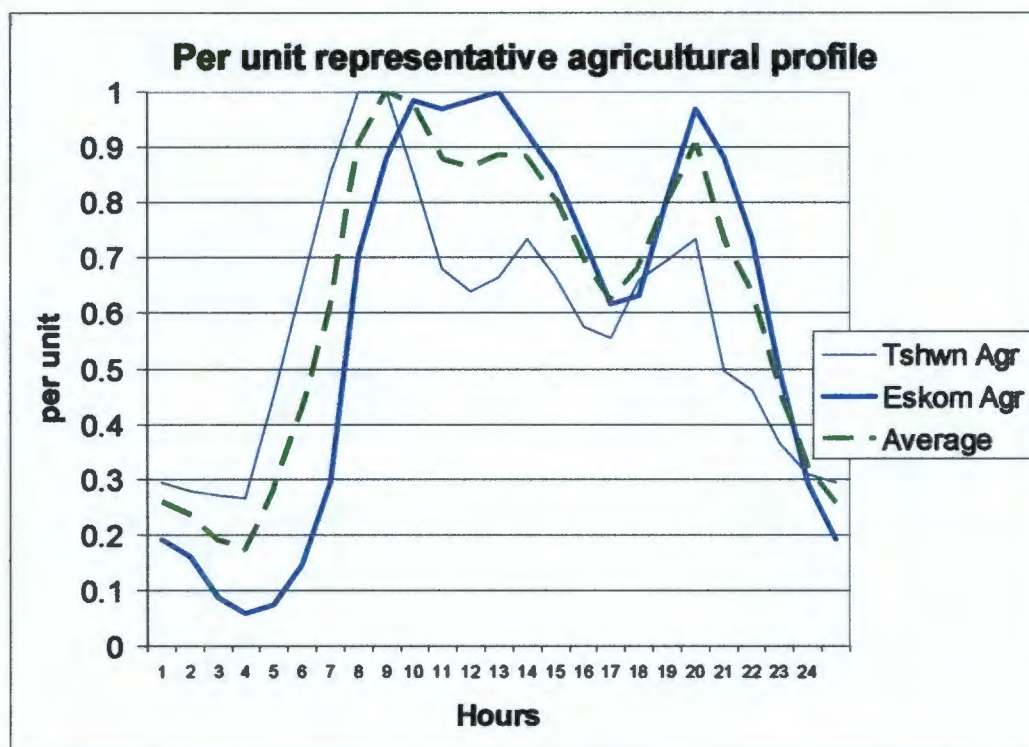


Figure 2-19 Comparison of agriculture daily per unit load profiles

2.3.13 Transport

The only electricity consuming devices used for transport are trains. There are freight and passenger trains. The daily profile shape for electric trains is shown in appendix B [Mbatha 2003]. The total electricity consumption for rail transport is divided 70% freight and 30%

passenger⁹ [Spoornet]. Rail freight plays a vital role in transporting mined ores and mineral commodities from mines to factories and harbours. Diesel trains are also used sometimes in tandem with electric locomotive as backup and for power boosting. Passenger rail is all electric and vital to commuter traffic. It occupies a larger share of the transportation mix in areas like Cape Town than in other metropolitans in South Africa. The difference between weekdays and weekend were adapted from the number of Cape Town Metro passenger lines running over a week and the number of Spoornet lines running for a week [Spoornet].

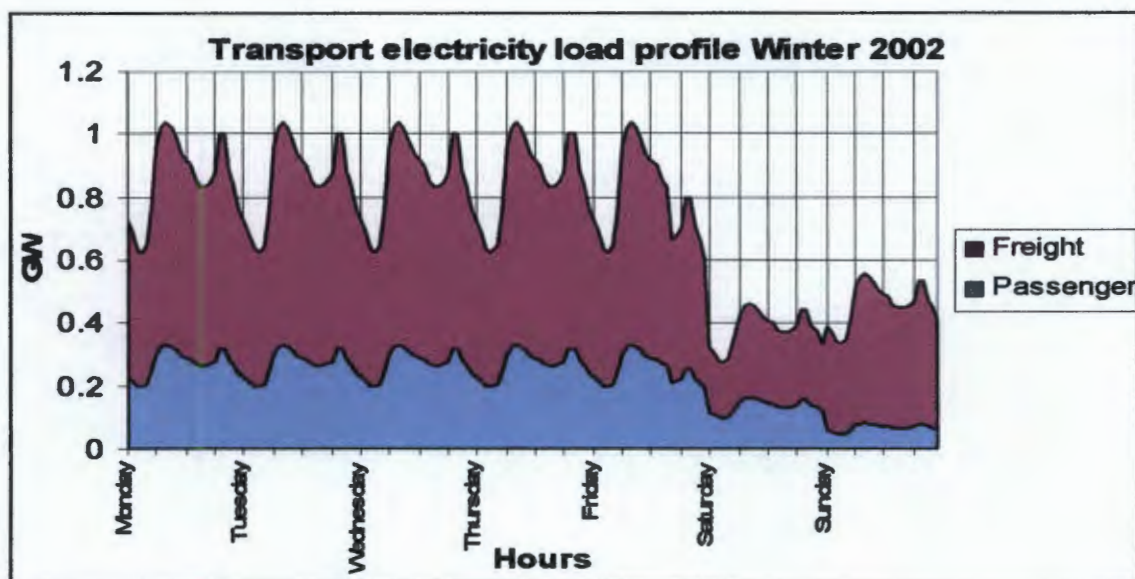


Figure 2-20 Rail transport weekly load profile 2002

The peak demand of 1.041 GW occurs daily at 8:00. There is a second peak at 19:00 which is slightly lower at 1 GW. The annual and weekly load factor is 0.69 as there is no seasonal variation in demand.

⁹ The share can even be 75% freight and 25% passenger as more electric trains are added to the approximately 800 freight trains in 2005.

2.3.14 Residential

The residential sector is categorised into three types of customer groupings namely : electrification, township and rural and urban customers.

2.3.14.1 Electrification

This sector includes customers that have been recently connected to the electricity network due to the electrification program initiated by Eskom and local governments in 1992. Over 4 million households have been connected so far and their total use is significant even though the level of each individual supply is basic. Development of this sector has been stimulated by the provision of free basic electricity (FBE) which is approximately 50kWh/month per connection. Total annual FBE from this sector is around 2000GWh which is half the total consumption. Load profiles for summer and winter weeks for the electrification residential sector are shown in the figures below.

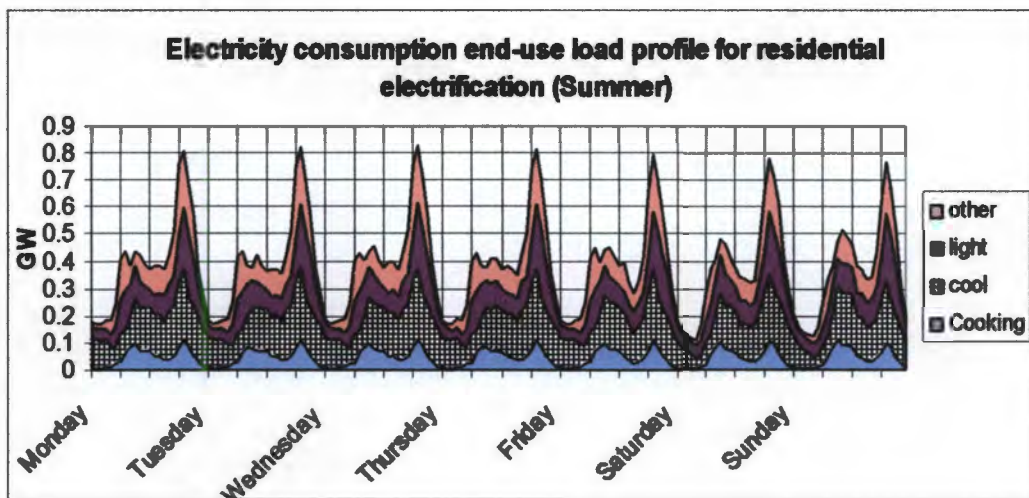


Figure 2-21 Electrification residential summer weekly load profile 2002

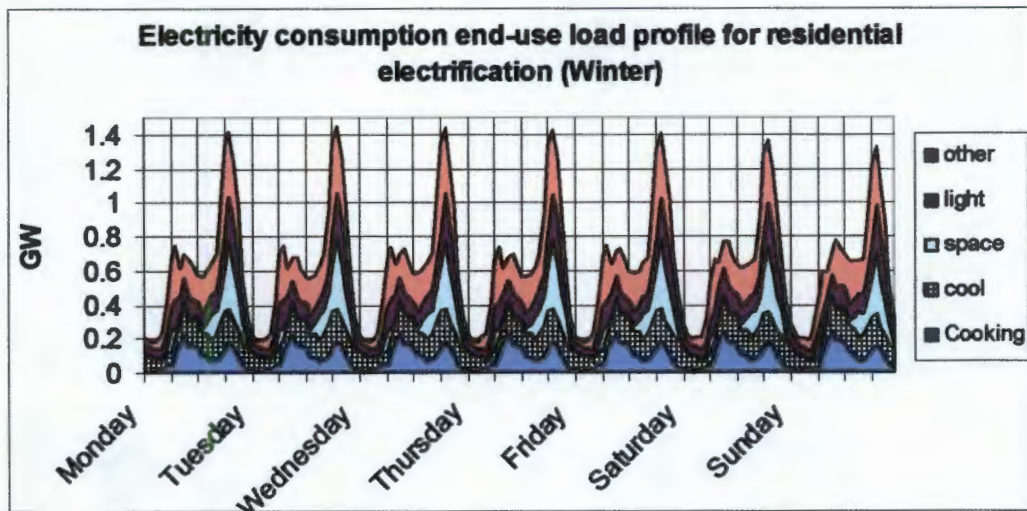


Figure 2-22 Electrification residential winter weekly load profile 2002

The main loads utilised by the electrification sector are for other load such as television, radio and small appliances and their load factor is 0.25 which equates to a peak demand of 561 MW. Cooling with refrigerators and lighting are significant loads in this sector with load factors and peak electricity demand of 0.51 and 264 MW and 0.39 and 288 MW respectively. There is no water heating load but there are space heating loads that operate only during winter months. Space heating has a very low usage with a load factor of 0.08 and a peak of 409 MW. The additional winter load results in a large difference in winter and summer consumption and peak demand. The winter peak of 1.444 GW occurs at 19:00 on weekdays whilst the summer peak, occurring at the same daily time, is 833 MW. The annual load factor is 0.34 and the winter week load profile is 0.44. There are less weekly variations than yearly variations as the latter includes seasonal use. There is a definite evening peak but the morning usage is more constant. This may be due to the working habits of residents that leave for work in the morning and return in the evening. This theory is supported by the higher morning peak on weekends.

2.3.14.2 Township and rural

This sector includes all establishes townships throughout South Africa as well as rural customers to which electricity extends. The annual sales are attributed 34% to rural customers and 66% to township customers [Hughes 2002]. Load profiles for summer and winter weeks for the combined township and rural residential sector are shown in the figures below.

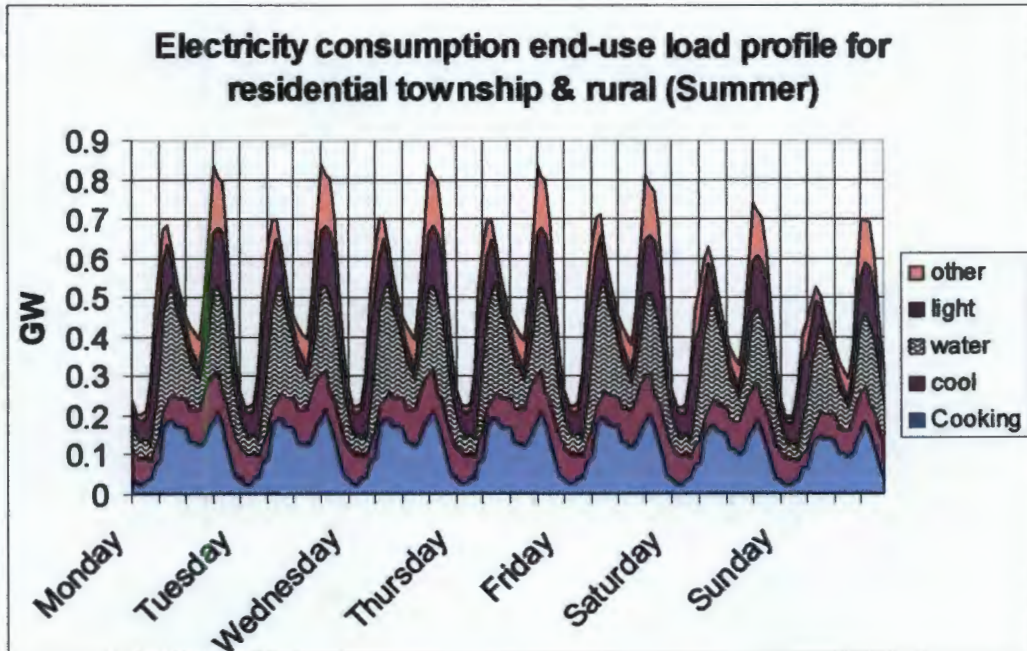


Figure 2-23 Township and rural residential summer weekly load profile 2002

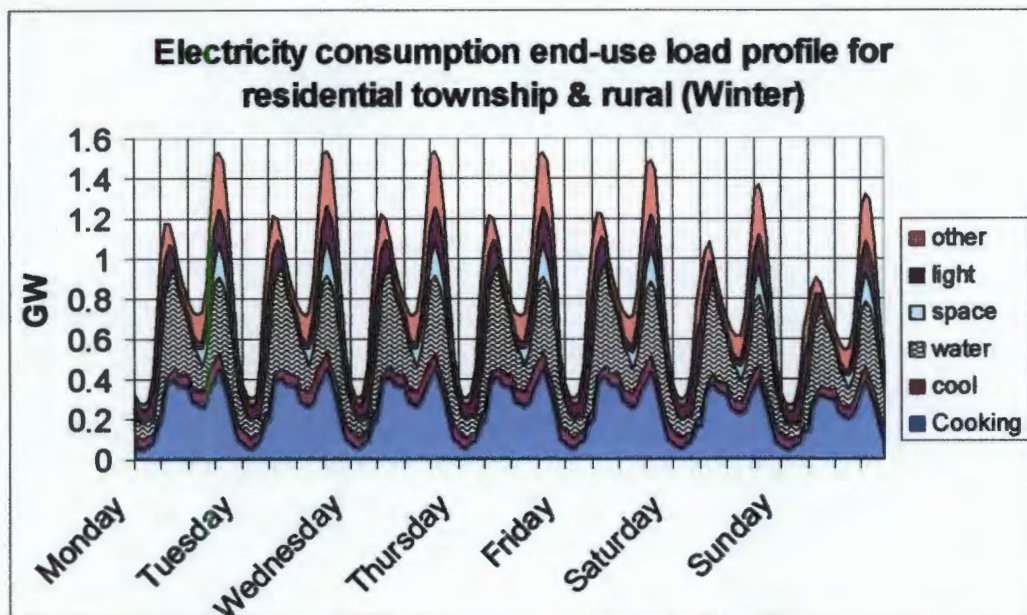


Figure 2-24 Township and rural residential summer weekly load profile 2002

The two main loads are water heating and cooking with load factors of 0.36 and 0.37 and peak demands of 511MW and 454MW. Lighting and other appliances such as televisions and radios consume similar amounts of electricity although lighting has a higher load factor of 0.41 whereas other loads only 0.25. The summer peak is 842MW on weekdays at 18:00 but

the peak climbs to 1.53 GW on winter weekdays because of the addition of space heating and the extra electricity required for cooking and water heating due to the seasonal temperature drop. The annual load factor for the whole sector is 0.41 and the weekly load factor is 0.55. There are two definite peaks, one in the morning at 7:00 and one in the evening at 18:30 – 19:00. Even though the water heating load profile is higher in the morning than in the evening the other loads are operated more in the evenings resulting in the morning peak being approximately 80% of the evening peak.

2.3.14.3 Urban

The residential urban electrical loads are the largest and include well established households in cities and towns around South Africa. Urban houses are larger than houses in townships or electrification areas and typically have more appliances like washing machines, multiple geysers, pool pumps and gate motors. Seasonal weekly load profiles for national urban households are shown in the figures below.

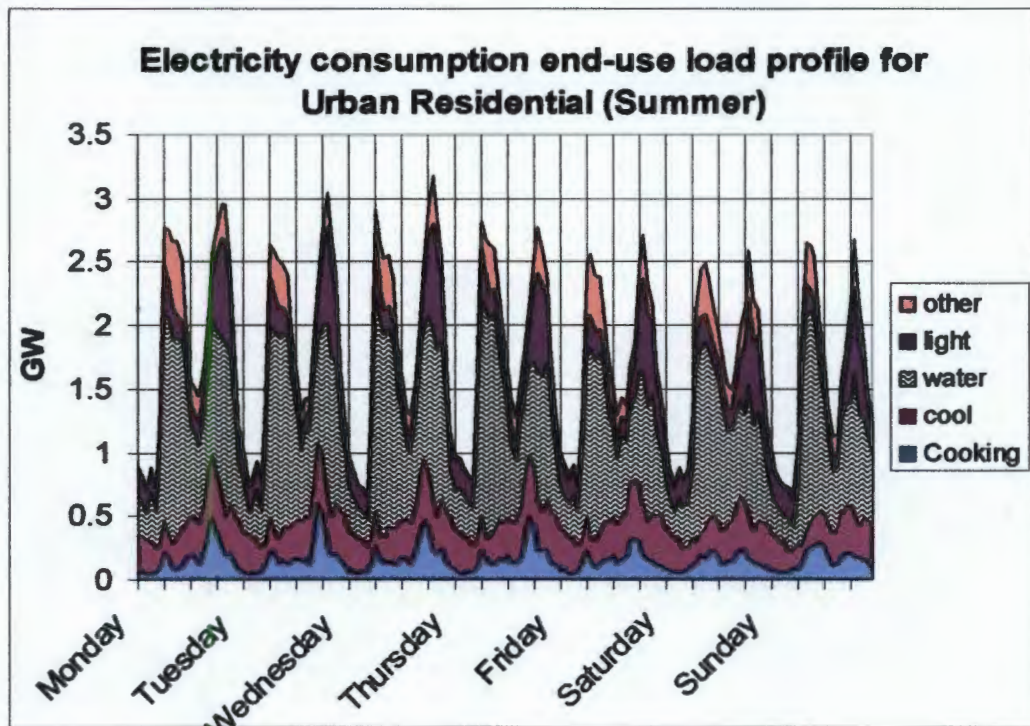


Figure 2-25 Urban residential summer weekly load profile 2002

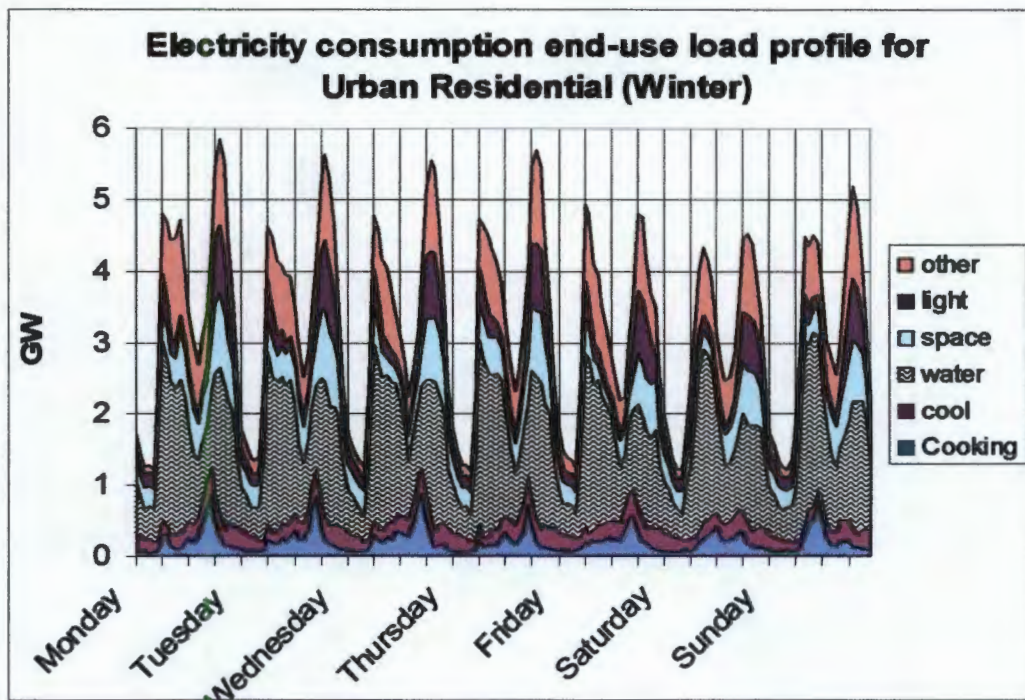


Figure 2-26 Urban residential summer weekly load profile 2002

The largest electricity consuming loads are water heaters that consume 3 times more (9020 GWh in 2002) than any other type of load in urban houses nationally. The second largest load is other appliances such as those used for entertainment, pool pumps, vacuum cleaners, washing machines and other devices used less regular than the essential loads. Even though water heating loads are large, they are in operation more often than other loads and have an annual load factor of 0.4 but other devices have a load factor of 0.26. This demand difference is reflected in the peak demand of 2.588 GW for water heating and 1.457 GW for other devices. Lighting and cooling loads consume similar amounts of electricity but cooling loads operate for longer hours and have an annual load factor of 0.58 and the lighting load only 0.31. Cooking and space heating have similar annual electricity consumption even though space heating is only operated in winter. The demand for space heaters is 1.022 GW and that for cooking only 868 MW. Both the summer peak demand of 3.23 GW and the winter peak of 5.85 GW occur at 19:00. There are two large peaks in the urban residential sector every day and the difference between the morning and evening peaks is greater in winter than in summer. The total annual load factor is 0.4 whilst the weekly load factor is 0.55.

2.3.14.3.1 Comparison of municipality data

The load profiles for the residential sectors of the Cape Town and Tshwane municipalities are included in appendix A. The selected Cape Town substation load profile represents a lower income residential category as fewer appliances are used. The shape can be compared to the electrification profile as there is a lower morning peak. The Tshwane profiles represent a mostly urban household load because of the high morning peak. A weighting of the two profiles can represent a mix of residential categories. The weighted average load profiles in figure 2-27 below represent a 67% low income and 33% high income mix. The weekly per unit winter profile calculated for Tshwane and Cape Town are also shown in addition to the seasonally reduced (55% of winter peak) summer profile.

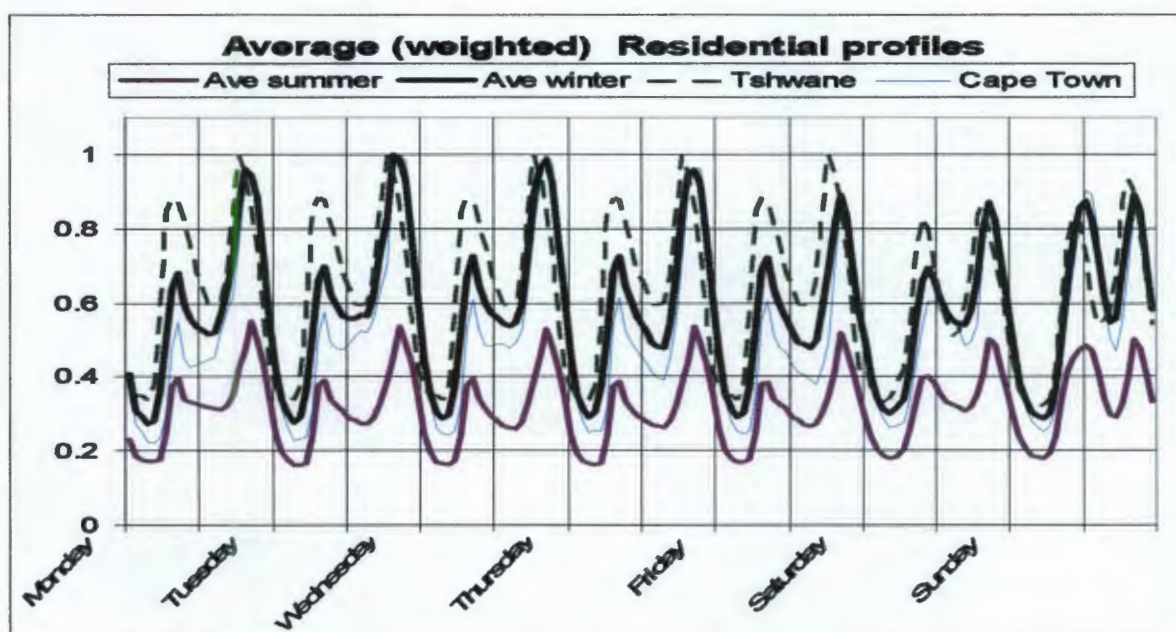


Figure 2-27 Comparison of residential weekly per unit load profiles

Load profile analysis provides insight into the patterns of electricity use. Electricity planning for growth of the number of residential loads is helped by accurate representation. The investigation into the use of energy efficiency equipment and the impact of potential demand side management can be improved with improved sector representative load profiles.

2.4 National electricity demand

2.4.1 National electricity consumption pattern

The electricity network in South Africa is large and serves a wide range of customers. Each sector serves an important function in the economy and society and the provision of electricity is essential in sustaining and developing the country. The patterns of use by each sector and their individual load types serve as an effective planning tool in monitoring usage and meeting future growth needs. Supply planning has to cater for industrial growth with high load factors and residential growth with lower load factors. The usage of generation, transmission and distribution equipment is directly proportional to the load. Planning at any level needs to consider the patterns of usage for matching correct supply capacities to demand and considering the expected utilisation growth.

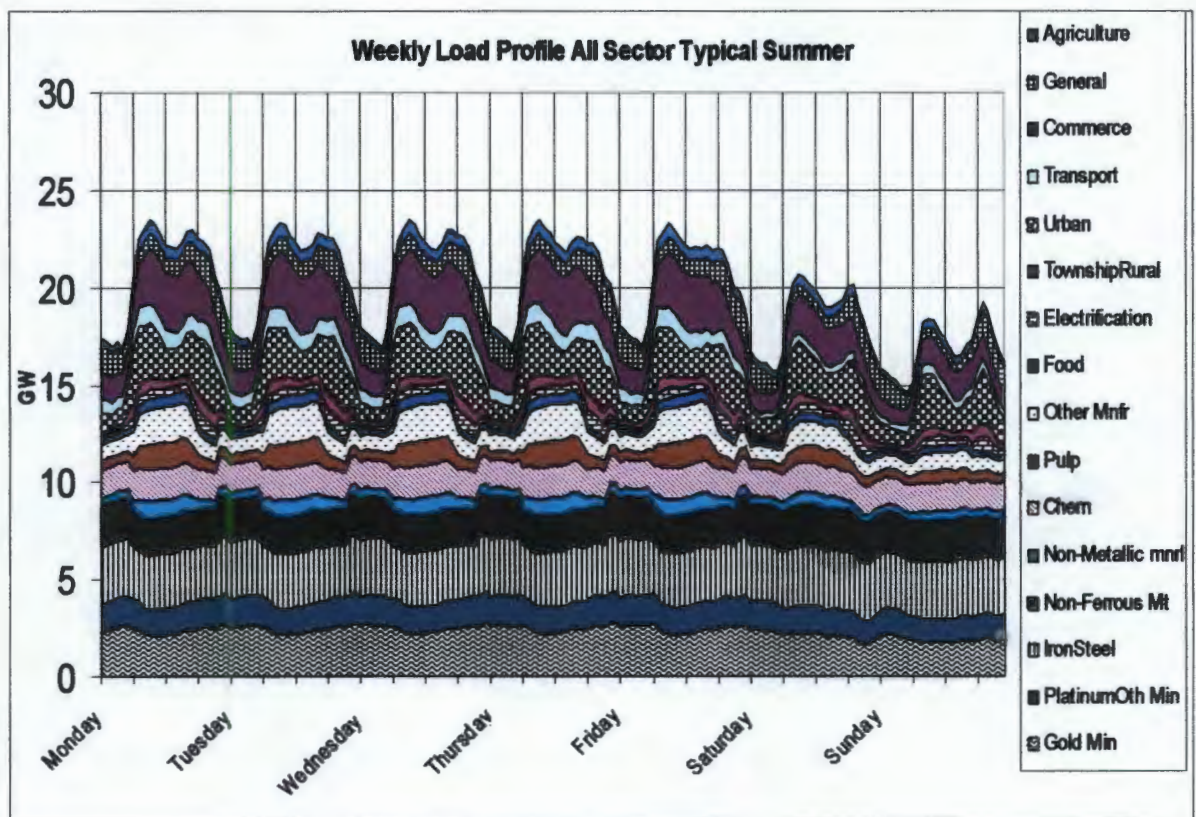


Figure 2-28 Total winter weekly load profile for all sectors 2002

The end-usage by all sectors for summer is shown in the figure above. There is a morning peak on all days at 9:00 except Sunday where there is an evening peak at 19:00. The summer peak is 23.5 GW and the minimum demand level is 14.9 GW on Sunday mornings. A slightly higher evening peak is observed on summer weeks in other system load profiles [NIRP 2003] and some load profiles would need to be adjusted for better correlation¹⁰. Urban residential electricity use is clearly the main cause of the two peaks but the additional morning contribution from other manufacturing results in the morning peak being higher.

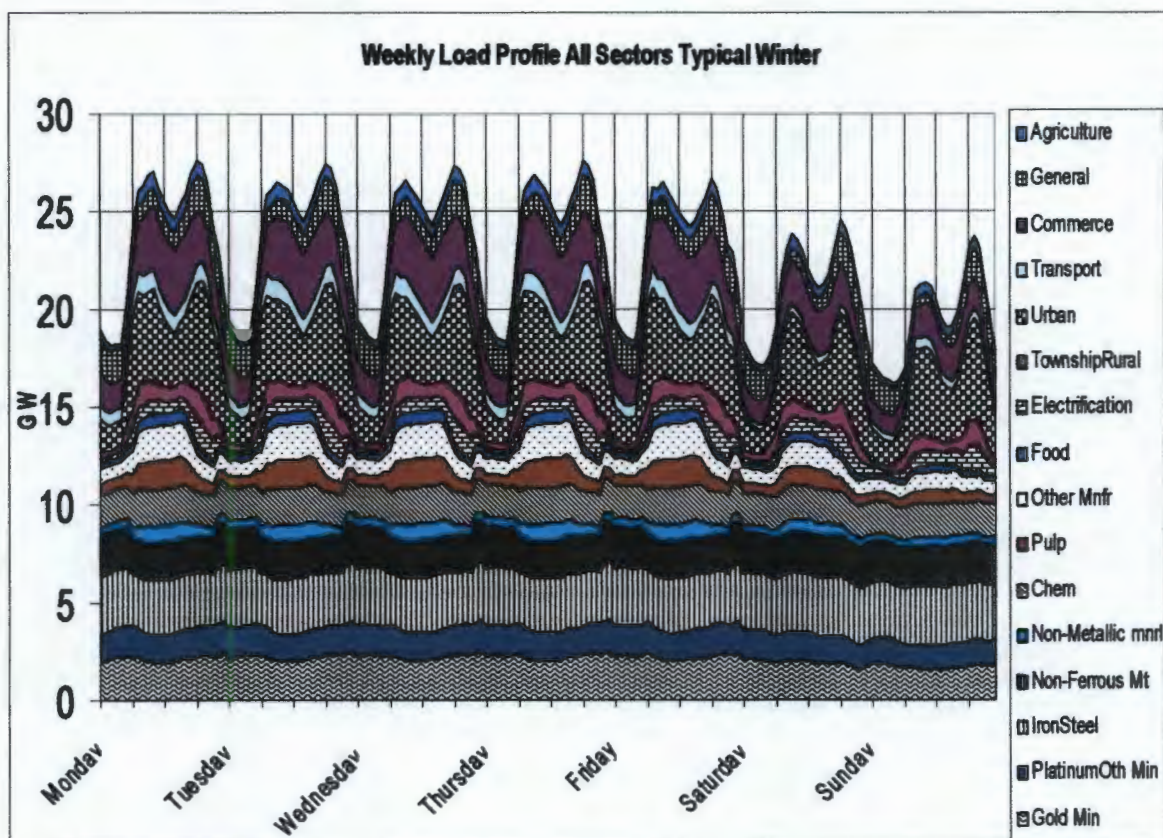


Figure 2-29 Total winter weekly load profile for all sectors 2002

The above figure shows a typical winter day. In actuality the peak will be slightly higher as the figure shows the average weekly peak. The peak of 27.6 GW occurs on Monday and Thursday at 18:00. There are two peaks reflective of the residential contribution to the combined profile. The morning peak is only slightly lower than the evening peak as more loads such as heating are used in the evening. The large industrial loads are mostly flat and

¹⁰ Typical summer could refer to different periods or average values where used in the NIRP of 2003

add to the base electricity demand. The minimum winter demand is 16.17 GW and is observed on Sunday at 5:00.

2.4.2 Peak loads for sector end-uses and annual load factors

The annual load factor for the total load is 0.76 which may be a little high as average peak values are used and not actual peak values. The load factor is a measure of the load against continuous full load (peak) operation. A load factor from an average peak load profile will not accurately reflect the real load factor. There are two ways to correct the load factor. The use of average electricity consumption instead of the actual amount of electricity can correct the load factor but more errors are introduced into the data in this way. The preferred method is to include the actual peak load value for the day of the year when it may occur by adding a magnitude increase to one day's profile. It is more important for load profile analysis to show the different load over time than to have an exact load factor that does not offer insight on the time patterns of load use.

Each sector will operate at different levels during the year in response to activity level and weather effects. The total yearly profiles for all economic sectors are shown in appendix C. The monthly average demand peaks and the variability of the total loads are shown. Hourly load profiles for each of end-use in all sectors are built so that a demand database exists and can provide information inputs for programs and modelling of energy performance. The annual load factor is a measure of the level of load utilization or fluctuations compared to full load conditions throughout the year. The peak load capacities experienced in South Africa in 2002 are also shown so that the magnitudes can be associated with each load type.

Electrification (Res)			Gold Mining			Chemicals & Petrochemicals		
Load Type	Peak GW	LFa	Load Type	Peak GW	LFa	Load Type	Peak GW	LFa
Cooking	0.24	0.28	Motive**	1.20	0.71	HVAC	0.02	0.95
Cooling	0.26	0.51	Heat***	0.09	0.56	Light	0.07	0.88
Space heating	0.41	0.08	Fans	0.19	0.93	Pump	0.45	0.91
Lighting	0.29	0.39	Pumping	0.67	0.56	Compressed Air	0.35	0.93
Other loads*	0.56	0.25	Lighting	0.11	0.89	Fan	0.14	0.95
Total	1.44	0.34	Industrial Cooling	0.23	0.67	Heat***	0.31	0.65
Township & Rural (Res)			Compressed air	0.58	0.75	Motive**	0.50	0.92
Cooking	0.45	0.37	home	0.26	0.37	Total	1.82	0.88
Cooling	0.12	0.57	Total	2.79	0.80	Pulp, Paper & Print		
Water heating	0.51	0.36	Platinum & Other Mining			Heat***	0.49	0.55
Space heating	0.17	0.10	Motive**	0.90	0.82	Light	0.28	0.57
Lighting	0.23	0.41	Heat***	0.08	0.60	HVAC	0.02	0.57
Other loads*	0.37	0.25	Fans	0.11	0.90	Motive**	0.73	0.57
Total	1.54	0.41	Pumping	0.28	0.64	total	1.52	0.56
Urban (Res)			Lighting	0.09	0.85	Other Manufacturing		
Cooking	0.87	0.22	Industrial Cooling	0.12	0.73	Motive**	0.52	0.64
Cooling	0.48	0.58	Compressed Air	0.27	0.75	HVAC	0.04	0.59
Water heating	2.59	0.40	Home	0.11	0.49	Fan	0.05	0.94
Space heating	1.02	0.19	Total	1.77	0.84	Heat***	0.73	0.57
Lighting	0.97	0.31	Iron, Steel & Other Ferrous Metal			Pump	0.20	0.58
Other loads*	1.46	0.26	Motive**	0.39	0.95	Compressed air	0.14	0.73
Total	5.85	0.40	Heat***	1.90	0.91	Light	0.19	0.60
Transport			Fans	0.12	1.00	total	1.83	0.63
Passenger	0.33	0.65	Pumps	0.12	1.00	Food, Beverages and Tobacco		
Freight	0.71	0.70	Compressed Air	0.12	1.00	Heat***	0.14	0.55
Total	1.04	0.69	HVAC	0.40	0.61	IndCool	0.12	0.78
Commerce			Lights	0.13	0.92	Pump	0.09	0.56
motive	0.67	0.69	total	3.02	0.94	Light	0.08	0.57
hostel	0.18	0.46	Non-Ferrous Metals			HVAC	0.01	0.58
lighting	1.20	0.54	Heat***	1.72	0.92	Fans	0.03	0.91
Hvac	0.97	0.57	Fans	0.10	1.00	Motive**	0.21	0.57
Heat	0.64	0.52	Pumps	0.06	1.00	total	0.64	0.64
total	3.42	0.61	Compressed Air	0.08	1.00	Total		
General			HVAC	0.14	0.61	Cooking (Res)	1.35	0.32
Buildings	0.71	0.61	Lights	0.07	0.92	Cooling (Res)	0.82	0.58
WaterWaste	0.22	0.54	total	2.12	0.94	Space heating (Res)	1.60	0.15
Street lighting	1.26	0.44	Non-Metallic Minerals			Lighting (Res)	1.40	0.36
total	1.88	0.58	HVAC	0.01	0.61	Other (Res)	2.02	0.30
Agriculture			Light	0.12	0.61	Water heating (Res)	2.91	0.42
Ind Cooling	0.06	0.76	Pump	0.09	0.60	Motive** (Ind & Com)	5.20	0.80
HVAC	0.04	0.56	Compressed Air	0.06	0.76	Heat*** (Ind & Com)	5.67	0.86
Light	0.05	0.57	Fan	0.06	0.97	Fans (Ind)	0.81	0.96
Pump	0.26	0.57	Heat***	0.23	0.65	Pumping (Ind)	1.92	0.79
Home&Hostels	0.32	0.37	Motive**	0.39	0.67	lighting (Ind & Com)	3.30	0.63
Fan	0.01	0.91	Total	0.95	0.68	Cooling (Ind)	0.50	0.76
Heat	0.04	0.55	**includes Material Processing ***includes Electrochemical heat processes			Compr. Air (Ind & Com)	1.53	0.86
Motive**	0.22	0.62				HVAC (Ind & Com)	1.63	0.59
Total	0.86	0.62				Hostels (Ind & Com)	0.86	0.42
*includes Television, Washing Machines, Motors and plugs						Buildings general	0.71	0.61
						Water & Waste	0.22	0.54
						Rail	1.42	0.50
						Total Load	27.97	0.76

Table 2-5 Peak loads and load annual load factors for all electrical end uses in all sectors 2002

2.4.3 Distribution, Transmission and losses

Distribution of electricity is the link between the consumer's load and the transmission network. The distribution network consists of lines and cables from below 1kV to 132kV. In 2002 there was a total of 363 845 km distribution lines and 198 341 km of distribution cables [NER 2002]. Electricity transmitted at higher voltages is stepped down using transformers. There were 352 169 distribution transformers in 2002 [NER 2002]. Distribution losses are caused by heating of lines, cables and transformers as well as unaccounted losses such as theft. There are more losses in the residential and commercial sectors as the capacity of supply is lower per connection and the reticulation is over large areas. Industries have large dedicated supplies and need less reticulation and have less distribution losses. The amount of distribution losses are in proportion to the actual sector consumption and the total distribution losses are 5.6 % of consumed electricity [NER 2002]. In reality the distribution losses will vary from sector to sector and from peak times to off peak times.

Most of the generation of electricity is confined to the north eastern part of South Africa and an extensive transmission network is required to transmit electricity between load centres. Electricity from power stations is stepped up to higher voltages for transmission over long distances. Electricity is transmitted at voltages 132 kV to 765 kV and there were 26 510 km of transmission lines and 362 transmission transformers in 2002 [NER 2002]. Higher voltage transmission lines have lower losses than lower voltages as there is less current needed for the same power¹¹. The transmission losses are 3.79% of distributed electricity¹² [NER 2002]. The load profile below shows the total system load profile on the national transmission lines and includes transmission and distribution losses.

¹¹ Heating losses are proportional to current squared and resistance not to voltage.

¹² These losses are small, considering the large distances between load centres, as result of the usage of 765 kV.

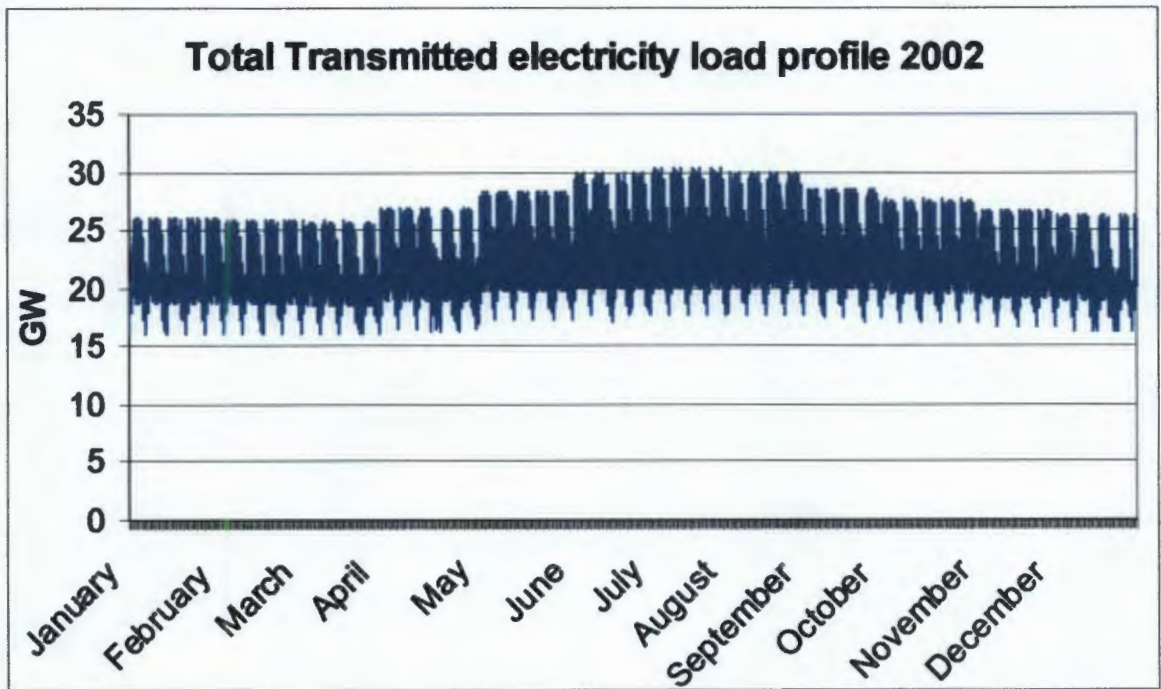


Figure 2-30 Total estimated yearly load profile on the system 2002

The maximum peak on the electricity network is 30.23GW and occurs on winter evenings at 18:00. The actual peak demand on the network was 33 724 MW in 2002 [NER 2002]. The higher peak demand is because exported electricity is not included in the model and average peak demand is used rather than actual peak demand. The 12% increase from the model peak to the actual will influence the supply plan as peak load will need to be available to supply the maximum energy demand. Electricity generation provides this load capacity and planning is needed to ensure that the demand can be met at all times.

2.4.4 Electricity consumption growth

The long term annual GDP growth for South Africa is expected to be 2.8% [NIRP 2003]. The following table shows the sector growths that can be expected in the near to long term [Howels et al 2003].

Sector	Growth elasticity to GDP %	Actual growth % (GDP growth 2.8%)
Industry Sector		
Iron and Steel	1.60	4.48
Chemical and Petrochemical	1.20	3.36
Non-Ferrous Metals	1.87	5.24
Non-Metallic Minerals	1.37	3.84
Transport Equipment	2.00	5.60
Machinery	2.00	5.60
Mining and Quarrying*	-0.59	-1.65
Food and Tobacco	2.00	5.60
Paper Pulp and Print	0.25	0.70
Wood and Wood Products	0.25	0.70
Construction	2.00	5.60
Textile and Leather	2.00	5.60
Non-specified industry	2.00	5.60
Transport Sector		
Rail	0.30	0.84
Other Sectors		
Public buildings	1.08	3.02
Commercial buildings	1.08	3.02
Urban residential **	1.30	0.87
Rural residential **	1.30	0.87
Township residential **	1.30	0.87
Electrification residential **	1.30	0.87
General services	1.08	3.02
Agriculture	0.45	1.26

* Gold mining has a -1.7 elasticity and other mining a 0.53 elasticity

** residential sectors growths are elastic to population growth of 1% and the elasticities are 1.3 until 2010 and 0.87 for years after 2010

Table 2-6 Electricity growth elasticities to GDP for each sector

The only negative growth is to mining as gold mining is expected to decrease in following years and the increases from other mining activities will not make this growth positive as gold mining is the most electricity intensive.

The figure below shows the past electricity consumption and the expected future consumption for all sectors in South Africa based on the growths in the previous table. The vertical line for 2002 values distinguishes between past statistical data and future projections.

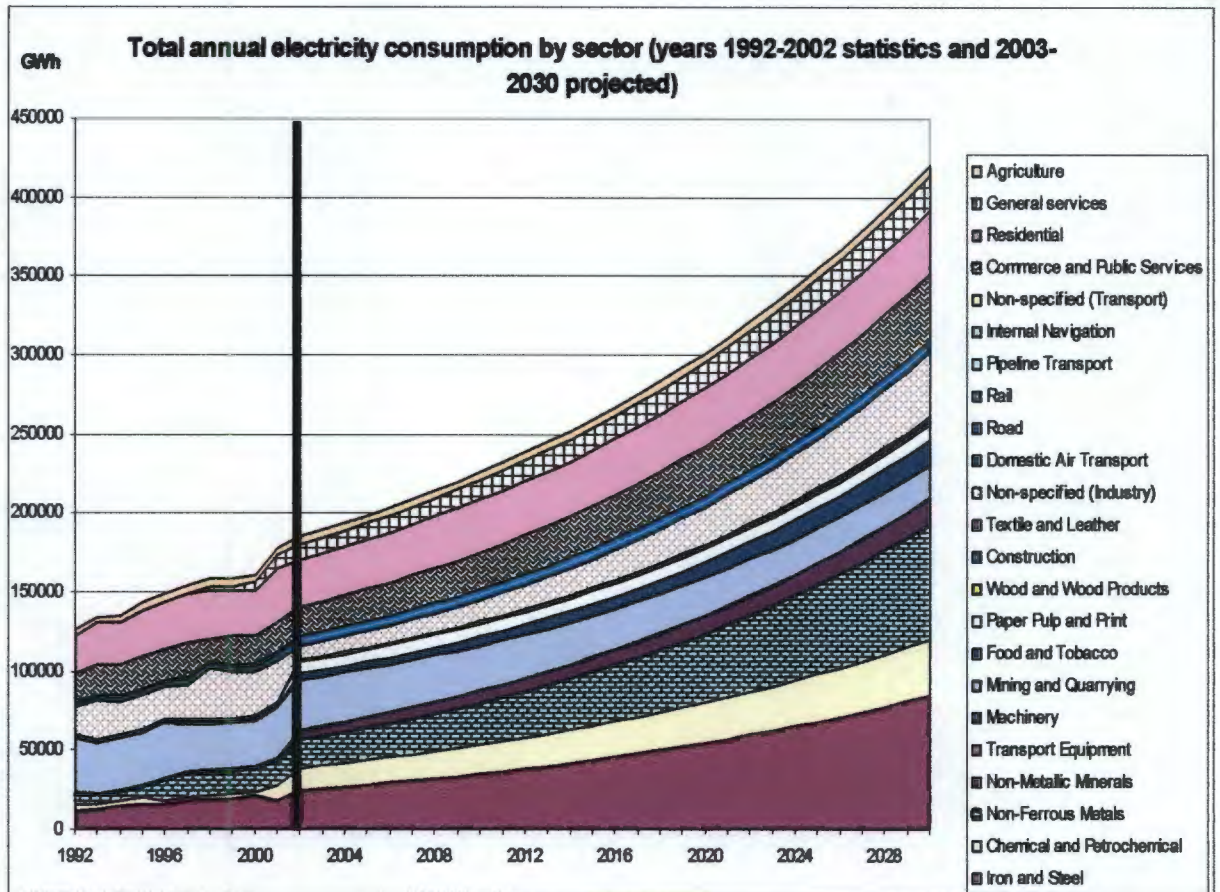


Figure 2-31 Annual electricity consumption by sector in the past and future

There was a lack of published statistical information on electricity consumption prior to 2000 which explains the large increase in the chemicals and petrochemicals sectors. The general services category has only recently been included and the non-specified industry included many activities that are now categorised in their respective sectors. Electricity consumption data was obtained from the DME energy balances¹³ from 1992-2001 and 2002 data was obtained from the NER statistics [NER 2002] and the DME baseline report [Hughes et al 2002].

¹³ energy balances from DME website: www.DME.gov.za

The yearly growth of electricity from all sectors is expected to increase every year as is shown in the figure below.

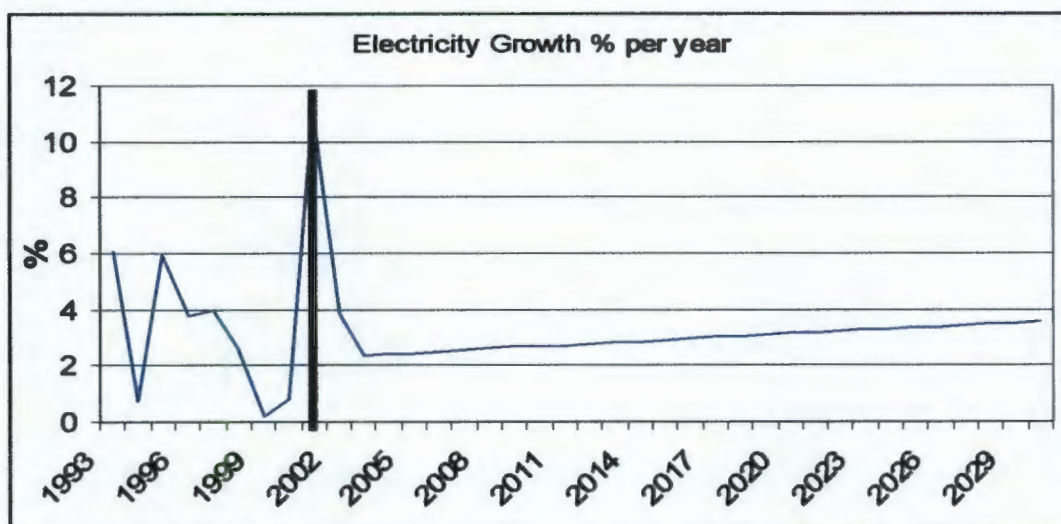


Figure 2-32 Percentage electricity growth past and future years

Statistical data was available from 1993 to 2002 and electricity growth varied significantly in each year although and there was only positive growth. The projected growth is based on long term growth for each sector and there is a steadily increasing growth between 2% and 4% expected.

- Medium growth levels have been used in this study and scenarios of low and higher growth can be calculated.
- Electricity growth elasticity to GDP for each sector could change as opportunities arise or are lost.

The database of load profiles could be repeated for any year by reassigning the appropriate electricity consumption to each load. Changes may need to be made to profile per unit shapes and end-use load composition as load use develops in time. The assumption about maximum and minimum usage periods could be solved if more profiles are measured for all sectors and for longer periods. Representation methodology using typical summer and winter profiles serve as a first attempt in analysing end-use load profiles for all sectors. The set of load profiles provide input data to an electricity model where demand based changes are modelled within an integrated resource plan. An end-use study is undertaken first to determine the potential load modifications within each sector from DSM and EE programs.

3 Demand Side options for electricity use in South Africa

There is recent commitment to energy efficiency by the South African Government as stated in the White paper on Energy and in the recent energy efficiency strategy [DME 2004]. The electricity industry from generation to distribution network is large and developed. Electricity use accounted for 26% of South Africa's energy demand in 2000 [DME 2003]¹⁴. There may be a large potential to conserve electricity or influence the national demand patterns to be in balance with the supply infrastructure. The extent of electricity utilization can be reduced or its' patterns modified using Demand Side Management (DSM) and Energy Efficiency technology. There are concerns that we will be running out of peak supply within a few years and immediate action is needed to avoid such shortages. The options are to build peaking power stations soon or to implement DSM that can shift some electrical load use to other times. Eskom, the national electricity supplier, has DSM programs for various customers groups that aim to reduce maximum peak demand. The progress of such programs is gradual as there is widespread use of electricity. The purpose of this study is to determine areas throughout South Africa where efforts can be concentrated to achieve the most promising results.

In-depth analysis of electrical end-use load profiles is needed to determine the potential effects of DSM and EE. This can then be used as resource inputs in the Integrated Resource Planning (IRP) process. Every electricity consuming device can be grouped with similar load to gain understanding of what end-uses are provided. Load profiles from all individual loads in all sectors show when the peak demands times are and what loads contribute to the peak. The potential for specific DSM and EE programs can be verified by determining the areas within sectors or within load types that contribute mostly to peak demand. Each program would need an operations strategy consisting of specific objectives, market penetration levels and cost and benefit comparison to be effective. This study considers the targets set out in the NIRP and shows the potential affects to the national electricity load profile that could be expected. The EE and load management targets apply to the years 2003 to 2011. Potential saving measures are also mentioned and can be analysed in a higher target scenario.

¹⁴ Integrated Energy Plan for the Republic of South Africa

Energy service companies (ESCOs) have the task of conducting energy audits and implementing energy efficient equipment and load management techniques. They would work in conjunction with the utility to identify measures that are most suitable. Eskom sponsors ESCO activities. Programs need to be verified to gain funding. Eskom is dedicated to DSM and has budgeted R350 million in 2004 to reduce and manage energy demand [Franz 2004]. Half of the costs of energy efficiency measures installed by ESCOs are sponsored by Eskom whereas all the costs of DSM measures are sponsored [Etzinger 2004]. Since each electrical load type used in each sector contributes to peak system loads and reduction techniques, both EE and load management, can be compared with end-use load profiles.

3.1 End-use load profiles

DSM and EE options consider modifying the timing of electrical end-use load operation or improving load efficiency. End-use load profiles are grouped according to their energy service to investigate the impact of demand based initiatives. Similar end-uses from the different sectors contribute in building national end-use load profiles. Industrial and commercial load profiles of similar energy service are combined as demand based initiatives are related whilst residential end-uses are kept separate as their demand programs are more unique. Industrial and commercial end-use categories are motive power, heat and electrochemical processes, fans, pumps, lighting, cooling, compressed air, HVAC, homes and hostels and other buildings such as municipality building, governmental departments, educational institutions and other public services. Residential end-use categories are cooking, cooling, lighting, space heating, water heating and other electrical appliances and devices. Two total load profiles are shown, one for summer (fig. 3.1) and one for winter (fig. 3.2), as there are seasonal variations in the load profile magnitude and shape.

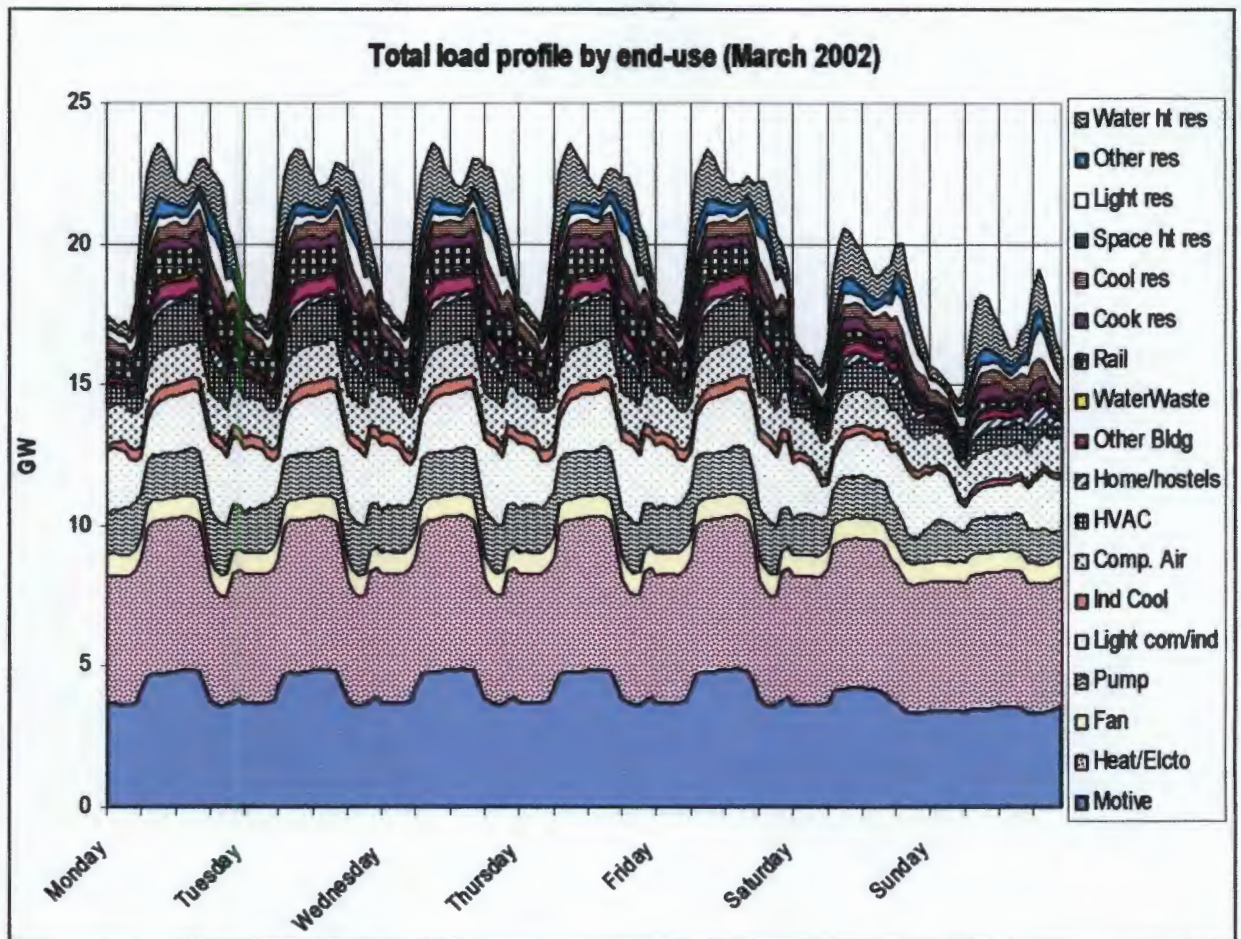


Figure 3-1 Total summer weekly load profile by end-use 2002

A peak of 23.6 GW occurs on weekday mornings at 9:00 and a secondary peak of 22 GW to 22.5 GW occurs on weekday evenings at 17:00. A base load of 17 GW is demanded on weekdays and is reduced to 15 GW on weekends. The load profile of Sunday shows an evening peak of 19 GW at 19:00 as there is little commercial activity and the total profile resembles the residential end-use load profile shape as the industrial loads are mostly constant.

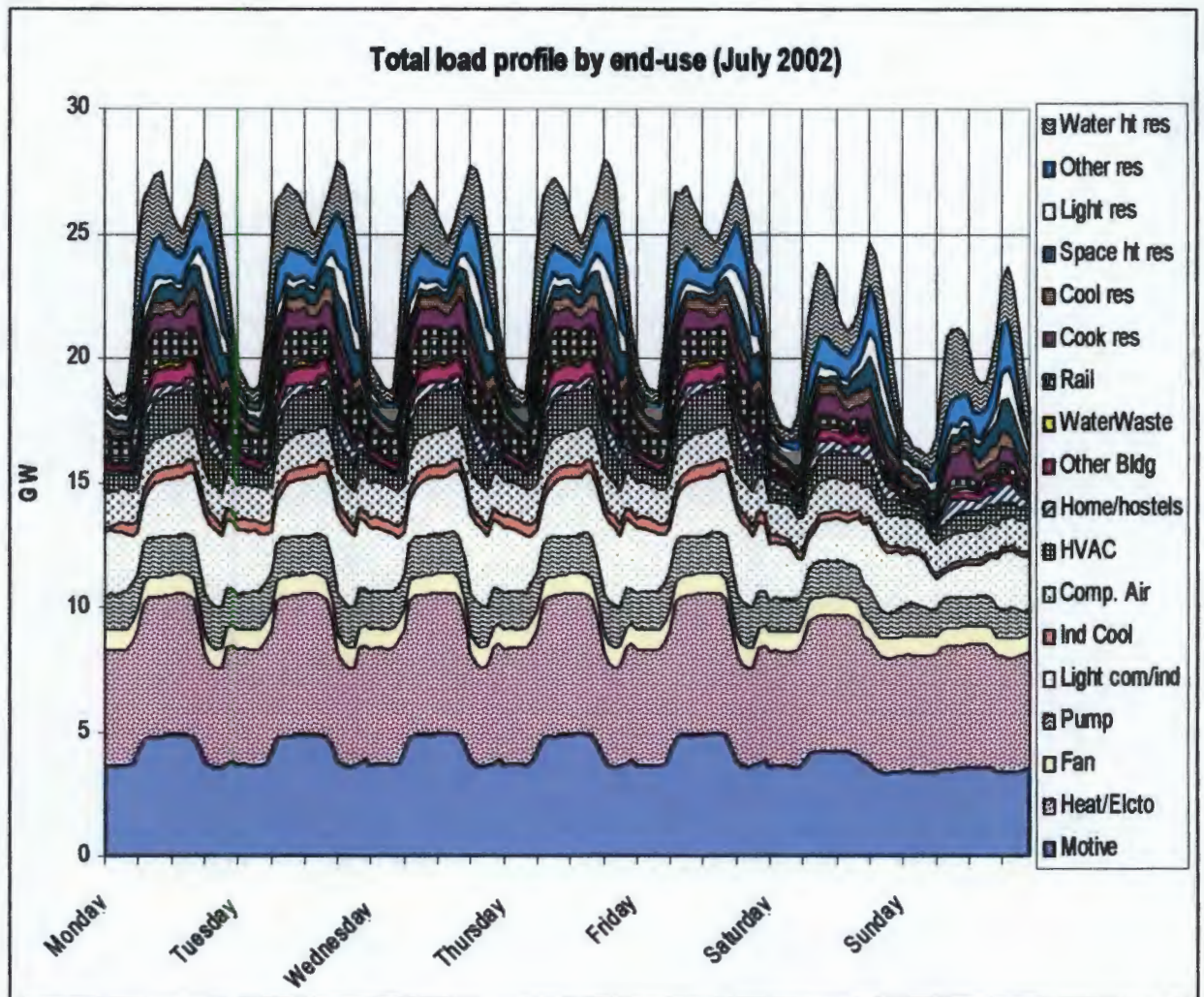


Figure 3-2 Total winter weekly load profile by end-use 2002

The total winter week load profile shows two distinct peaks every day. A morning weekday peak of 27 GW occurs at 9:00 and the maximum peak of 28 GW occurs at 18:00 on winter weekdays. The weekday minimum demand is 18.6 GW which is reduced to 16 GW on weekends. There was a 9% increase in the minimum load from summer to winter whilst a 19% increase in the maximum peak. Residential end-uses are the cause of the winter/summer variations as can be seen in the above figures. The winter increases came from residential water heating loads, space heating, cooking and other uses.

It is possible to analyse which electrical end-uses contribute to the winter peak. The table below shows the loads in operation during the winter peak hour and the percentage of the total load at that time.

Electrical End-use	Winter peak GW	% peak total	Consumption GWh	Max. peak GW	LF
Motive	3.83	13.70	36339	5.20	0.80
Heat/Elcto	4.29	15.34	42751	5.67	0.86
Fan	0.81	2.88	6812	0.81	0.96
Pump	1.61	5.75	13318	1.92	0.79
Light com/ind	3.24	11.59	18235	3.30	0.63
Ind Cool	0.45	1.62	3328	0.50	0.76
Comp. Air	1.29	4.61	11523	1.53	0.86
HVAC	1.44	5.15	8411	1.63	0.59
Home/hostels	0.77	2.74	3112	0.86	0.42
Other Bldg	0.57	2.03	3744	0.71	0.61
WaterWaste	0.14	0.50	1056	0.22	0.54
Rail	1.20	4.27	6246	1.42	0.50
Cook res	1.04	3.72	3731	1.35	0.32
Cool res	0.66	2.36	4190	0.82	0.58
Space ht res	1.33	4.75	2121	1.60	0.15
Light res	1.24	4.43	4414	1.40	0.36
Other res	1.96	7.01	5310	2.02	0.30
Water ht res	2.11	7.54	10639	2.91	0.42
TOTAL	27.97	100.00	185277	33.88	0.76

Table 3-1 End-use peak loads and load factors

An error of a 0.2% increase in total consumption occurs when the 96 yearly load profiles are added to build the total load profile. The error is due to the use of accuracy to one decimal place when aligning the magnitude of each load profile to consume the correct electricity for that load. The peak value is selected for each profile so that the entire yearly load profile can shift up or down and the sum of all demand in GW for the full year of 8760 hours can equate to the appropriate share of electricity consumed in GWh.

Even though motive use and heat/electrochemical use in industry account for 29% of the peak load, their load factor is over 0.8 and they are not operating at full capacity during peak times. Lighting for industrial, commercial and residential sector consume 16% of the peak load and are 180MW below full capacity as the peak load occurs during the beginning of evening. The residential load for lighting is increasing during peak time whilst the industrial and commercial load is decreasing. A faster rate of turning off lights in the commercial sector would significantly lower the peak demand as the operation of commercial lights in buildings

would not overlap the times of street lighting turning on. The shorter day time hours of winter than in summer results in a higher overlap between commercial lights and street lights being on.

Residential loads are almost at full operation levels during peak times and contribute 30% of the total winter peak load. Any DSM strategy would have to aim at reducing the consumption of these residential winter load by using energy efficient technology or using method for shifting some loads to other times.

3.2 Load profile analysis by end-use and Demand side resources

Suitable programs to change the demand can be identified by analysing the characteristics of the load. Load characteristic can be changed in two ways: namely through increasing their electricity efficiency in providing the same service and by influencing the time of operation through demand side management techniques. The load profiles of each end use within each sector will be modified with DSM. Energy efficiency will reduce the demand at all times and can be visualised by decreasing the magnitude of a load profile. Load management techniques aim at reducing demands at certain times and the shape of the profile could change by shifting loads, clipping peaks and other load use modification. Each end-use profile changed with DSM practices will contribute to the total system load. A strategy could be designed to produce a preferred load profile by selecting an appropriate mix of end-use loads that can be modified with DSM.

The objectives of the two ways differ as energy efficiency reduces consumption whilst DSM may not necessarily reduce any overall consumption and may even increase consumption. DSM aims to improve the load's performance from the utility perspective and methods which reduce the costs of supply are sought. An energy efficiency program will have most benefit from constant loads as the electricity savings are greater but utilities may see such programs as lost revenue. A utility would therefore prefer energy efficiency programs that mostly reduce consumption at times of peak demand. The preferred load profile will depend on the dispatch characteristics for generating stations. A load profile with constant or gradually increasing peaks will be favoured by slow-responding stations as the load can be matched more exactly.

Tariff structure changing is an effective means of reducing peak demands. DSM tariff structures based on time-of-use have been offered to mining and industrial customers since the early 1990's by Eskom. Since the late 1990's Eskom offers industry options of reducing demand at peak times, 7:00 to 10:00 and 18:00 to 21:00 [Franz 2004]. ESCOs are the means to realise the savings through both DSM and energy efficiency, as mentioned previously.

The procedure for locating areas with possible DSM and EE is directed at similar types of loads. The load profile for the peak winter week for each end-use type in 2002 are shown in figure 3-2. In reality the peak would be higher but due to the growth of the demand every year the peak could occur at different weeks and therefore monthly averages are used and each week of a specific month has the same load profile. The loads that contribute to each end use types are similar and DSM programs could be focussed in a particular technology. Residential end-uses are considered first and commercial and industrial end-uses are grouped subsequently. Similar end-uses are grouped for the commercial and industrial sectors as DSM programs target similar activities. Residential DSM programs are very different from commercial and industrial programs and are therefore dealt with separately.

3.2.1 End-use profiles for residential customers and DSM opportunities

There are three categories of customers in the residential sector. Urban houses are the largest consuming category in the residential sector and include all houses in cities. Urban loads comprise of a wide range of end-use as they utilise a range of electrical appliances. Township and rural houses are grouped together as they have similar electrical load usage. Their types of loads are more basic than for urban houses. The third category is newly electrified houses. Almost all of these customers have been provided with electricity in the past 10 to 12 years as part of the low cost housing reconstruction and development program (RDP). Pre-paid electricity use is the method of payment and metering for electrification customers whereas the other categories have mostly monthly accounts and meter reading is required. Households are assisted with 50kWh of free basic electricity every month which is most the electricity used by low income households [DME 2003]¹⁵.

¹⁵ Free basic electricity guidelines, Department of Minerals and Energy

Residential loads consist of stoves and ovens for cooking, fridges and freezers for cooling, electrical heaters for space heating during winter, electric geysers for water heating, incandescent and fluorescent lighting and many other loads used for entertainment, cleaning, recreation, security and convenience. Residential loads generally follow a similar pattern which is reflective of household activity namely a morning peak and a higher evening peak. Awareness and familiarity with electricity use is important not only for conservation and cost reduction but also for personal safety. The cost of information campaigns to improve efficiency of electrical appliance is assumed to be minimal compared with other measures such as equipment replacement. Higher expenditure in advertising and programs will achieve larger market penetration. Electricity savings from energy efficient practices is delayed as it is difficult to influence change in the consumer's behaviour.

Residential loads are operated on the lower load factors than loads for commercial or industrial activities. The larger winter peak demands are caused by the additional operation of some residential loads which are utilised less in summer months. Demand resource programs should be focused on reducing peak times especially in the residential sector. Such programs could include EE, Load Management and tariff structure changing. Energy efficiency and load management options are considered for specific loads but tariff structures affect all loads.

The residential sector comprises many electrical loads within each household. Concentration of residential loads is low as households are spread over wide areas. Residential DSM programs are therefore more difficult to implement and the greatest program benefits should come from high density housing. An example of this barrier is tariff restructuring for residential customers. Households usually only meter electricity use (kWh consumption) and a fixed rate is applied to all units equally. It is difficult to justify the costs of installing more meters for time-of-use or maximum demand tariff as the usage is low. Research is needed into designing suitable metering in the residential sector which reflects the costs of supply and can be understood by house dwellers that are generally unfamiliar with electricity delivery. One possibility to reduce peak demand is to encourage increases to the load factor through cost discounts [Grover et al 2005], but accurate demand measurement would be needed, not just estimates, to allocate discounts correctly.

3.2.1.1 Residential water heating

The largest residential electric loads are geysers or electric water heaters. There are two daily peaks of water heater usage with the morning peak being larger than the evening peak as seen in the figure below.

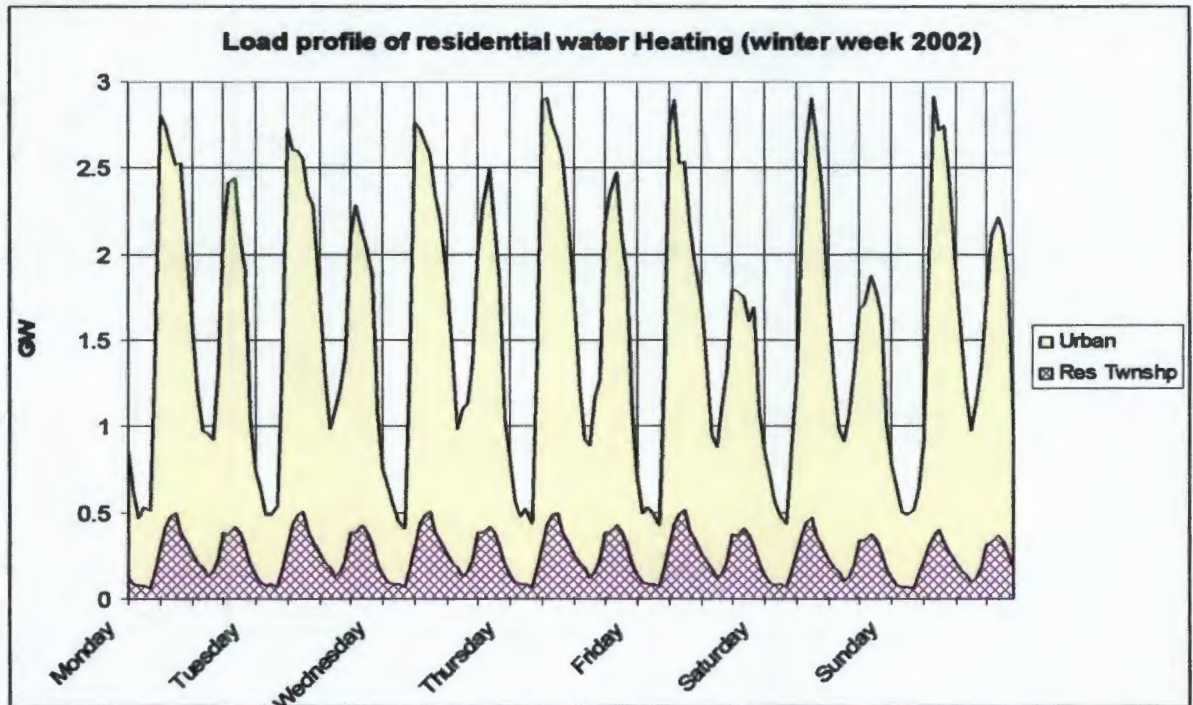


Figure 3-3 Residential water heating winter weekly load profile 2002

Water heating loads exist for urban and township customers and are not yet being used by electrification customers. Water heating has the highest peak demand of all residential end uses with a combined total peak of 2.85 GW occurring between 7:00 and 9:00 on winter days. Urban water heaters account for 80% of the load. There is also a daily evening peak occurring between 18:00 and 21:00 daily. A constant demand of 0.5 GW occurs during winter weeks but drops to 0.28 GW for summer weeks. The peak demand for summer weeks is reduced to 2 GW.

3.2.1.1.1 Water heating load management

There is already a large amount of geyser control installed in the form of ripple and radio control. Only urban water heaters have been controlled and there is approximately 700MW of geyser load controlled by municipalities [Henderson 1997]. The figure above includes both controlled and uncontrolled loads. The water heaters are switched off during times of peak demand and switched on during other times. The full capacity saving cannot be

achieved as the level of service needs to be maintained in order to meet customers hot water needs with minimum inconvenience. Some customers may override the control equipment if they are unhappy with the centralised control. Effective strategies are being sought to increase the controllable load through volumetric measurement [Lemmer et al], microprocessor control [Jackson et al] and a staggered turn on to reduce later peaks.

Load management of water heaters is considered as one of the DSM options in the integrated resource plan. The target mentioned in the plan is 49MW shifted from peak demand times. A further 49MW is achievable if the load management system has a high coincidence factor. The effects of water heater control can be integrated into the total water heating load profile using a load profile of the controlled load. The average daily water heating load profiles in the figure below show the effects of ripple control [Eskom DSM]. There is a reduction in demand during morning and evening peak demand times. The control is flexible and can be operated depending on system demands. The level of hot water demand needs to be maintained and the geysers are operated after peak times. Shifting the demand produces new peaks that could be over 40% higher than the initial peak but are now at off-peak times.

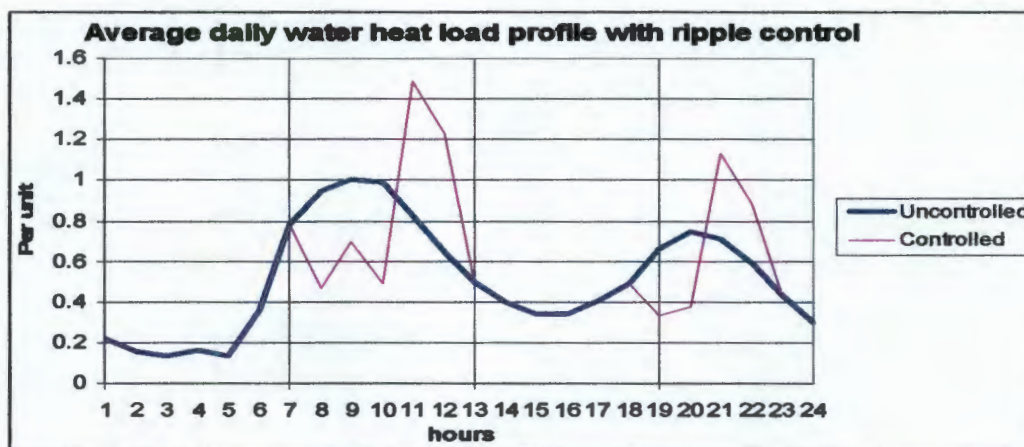


Figure 3-4 Load profile of uncontrolled and controlled water heater

Customers, such as redistributors, that are charged a maximum demand may have higher costs from the new peak in their total load profile [van der Walt 2003]. It will be more difficult to justify large ripple control systems unless switching-on strategies can be adopted to reduce the amount of geysers that can be turned on immediately after the peak times. Nevertheless, the benefits are seen on the larger system load profile with a flatter shape. For

the purposes of modelling DSM, this profile has been used although in reality the control is more flexible.

The amount of saving depends on the loads that are available for control. Approximately half of the controllable loads may be unavailable due to bypassing of the control relay but if customers are satisfied with the level of hot water service there could be higher usage. The annual target of 49MW reduction at peak demand times is double the amount of geysers load are installed with control equipment. An average geyser load is 3,1kW and the cost of the control relay including installation is R1050 [van der Walt 2003]. The cost to install 98MW of controllable geyser load is R33.2 million as 31 613 geyser will need the control equipment.

3.2.1.1.2 Solar water heating

South Africa has high intensity of solar radiation and solar water heaters could be installed. The hot water from the solar water heater can be used directly or can supply the electric geyser with water if further heating is needed. The cost of the solar water heater is high but most the electric load is replaced. Research and demonstration into the load profile of hybrid solar water heaters would indicate the potential for their implementation. It is expected that a smaller amount of the existing morning peak could be reduced compared to the evening peak as the solar water heater is heated throughout the day. The cost of a hybrid solar water heater can be 4 times the cost of a regular electric geyser [De Villiers et al 2000] but the savings to the customer and utility are large and can be determined with a solar water heating load profile. The cost of solar water heaters included with a water tank and installation costs ranges from R3000 to R14 000 for residential applications [Cawood et al 2002]. The heaters need to be durable as they are open to the elements and need to withstand hail storms. Indirect water heating using antifreeze is needed when the temperature could drop below freezing. Sufficient insulation of the water tank keeps the water warm over night until the heating cycle can resume in the morning.

Massive implementation of solar water heaters could reduce both the morning and evening electricity peaks in residential homes. The main obstacle to overcome is the initial cost and years required for payback which will decrease as more heaters are installed and as electricity rates increase. Installation in new houses could be more attractive than replacement after a few years. Low-income households may begin using hot water heaters which could place a

constraint on existing power station capacity. Cost effective energy efficient solutions such as stand-alone solar water heaters could lower electricity demand growth rates yet still provide adequate service.

3.2.1.1.3 Efficient hot water use

Low-flow shower heads are one of the energy efficient measures targeted in the NIRP. The annual capacity reduction is 2.38MW with annual electricity savings of 8.22 GWh. Hot water use reduction through awareness has also been selected in the NIRP with a target of 0.47MW/year and 1.63 GWh/year. It is assumed that the cost of shifting to efficient hot water use is minimal and costs are therefore excluded. There may be a larger market penetration of efficient technology through direct marketing campaigns. Lowering the geyser temperature to a level where convenience and comfort are not compromised result in easily implemented energy savings. Efficient hot water use such as washing dishes in a sink or bucket instead of using running water saves energy and water.

Centralised water heaters for large buildings such as apartment blocks can be more efficient than many single water heaters. Small centralised heat pumps with hot water storage can save over 30% energy use per house [De Villiers et al 2000]. Opportunities for heat pumps to provide extra heating may exist if there are large HVAC systems.

3.2.1.2 Residential Space heating

Space heaters consist of heating elements used in bar, oil or under-floor heating. Urban households are the main consumers of electric space heating but low-income electrification households also contribute 25% of the peak demand as shown in the figure below.

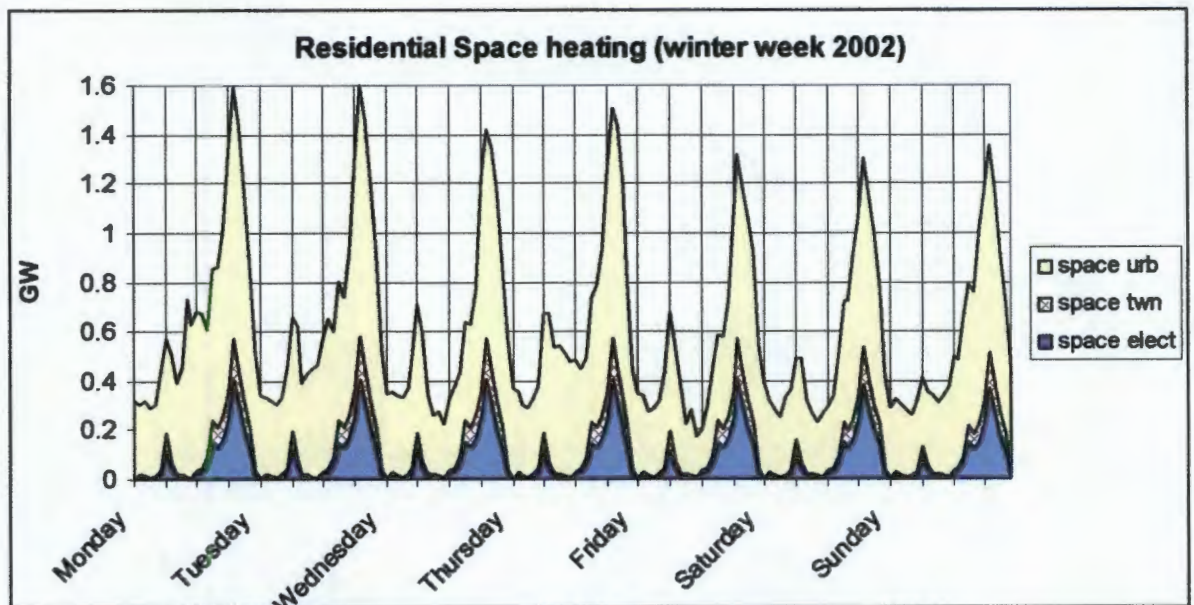


Figure 3-5 Residential space heating winter weekly load profile 2002

Space heating loads occur during winter months. A peak of between 1.3GW and 1.6GW is observed on peak winter days at 19:00. There is significantly more space heating used by electrification customers than township customers as the efficiency of heating homes for electrification customers is low due to the lack of ceilings and insulation from cold weather. Urban space heating accounts for 65% of the peak demand and 80% of the total energy as there are higher off-peak demand times compared with the other residential groups.

3.2.1.2.1 Fuel switching to gas

The winter evening peak from space heating contributes to the maximum peak demand on the system. Fuel switching to gas is possible with LPG or piped gas. Space heaters have a low load factor ranging from 0.08 for low income residential households to 0.19 for urban residential households. The cost of the new equipments and the cost of the gas compared to the electricity savings will determine the likely payback. Generally the costs of using LPG are more expensive than using electricity in providing the same end-use service. There are benefits to using gas as it is portable and available countrywide but its applications are more limited than with electricity. Switching to gas can benefit the electricity supplier as the customer only pays a fixed rate for electricity at peak demand times and gas could reduce peak demand consumption of electricity.

3.2.1.2.2 Thermal efficiency in building

The electricity costs to heat a space can be reduced by careful building design and by incorporating passive solar heating. Ceilings and other construction methods for low-income houses offer a potential for electricity saving of 70% in space heating energy requirements [Spalding-Fecher et al 1999].

3.2.1.3 Residential Lighting

Lighting in residential applications is currently predominately incandescent bulbs. The load profile for residential lighting is as expected with a large evening peak.

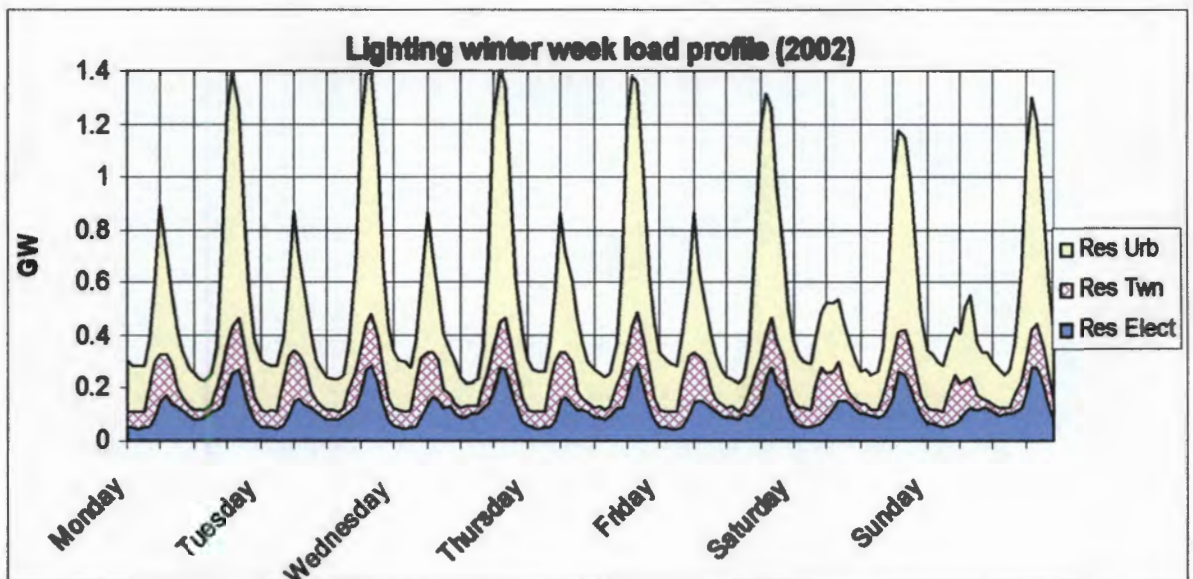


Figure 3-6 Residential lighting weekly winter load profile 2002

The demand for lighting by residential customers has two daily peaks, typical of most residential loads. The total maximum peak load of 1.4GW occurs on winter weekdays at 19:00 and a morning peak of 0.87GW occurs at 6:00 on the same days. Weekend use is similar with regards to the constant demand of about 0.3GW but the peaks are reduced.

3.2.1.3.1 Energy efficient lighting

Eskom has embarked on an efficient lighting initiative to reduce residential lighting loads by 820MW over 20 years [Delpont 2003]. Compact fluorescent lighting (CFL) can save up to 80% of the electricity consumed by incandescent lighting. The cost of CFLs have decreased because of more favourable currency exchange rates for imported bulbs and through

international market development. A CFL typically costs R10 to R30 depending on the wattage, type and manufacturer. It is estimated that 500 000 CFLs could replace incandescent bulbs every year [De Villiers et al 2000]. If each replacement saves on average 50W of electrical load, the annual reduction in demand would be 25MW. The annual capacity reduction target for CFLs in the NIRP is 25.2MW. Eskom's 20 year target cannot be reached at this annual rate and the annual market penetration should be doubled in the second ten year period to meet the target. A higher market penetration at this time could be possible with a further decrease in prices from local market development and technology improvement in CFL manufacturing.

3.2.1.4 Residential other end-use

Other end uses include electrical loads such as television, radio, gate motors, vacuum cleaners, pool pumps, ironing, clothes washing and drying machines, kettles and other devices. Urban residential households are the major contributors to this load category. The growth of other end uses will depend on the household income level as more appliances are bought and used more often.

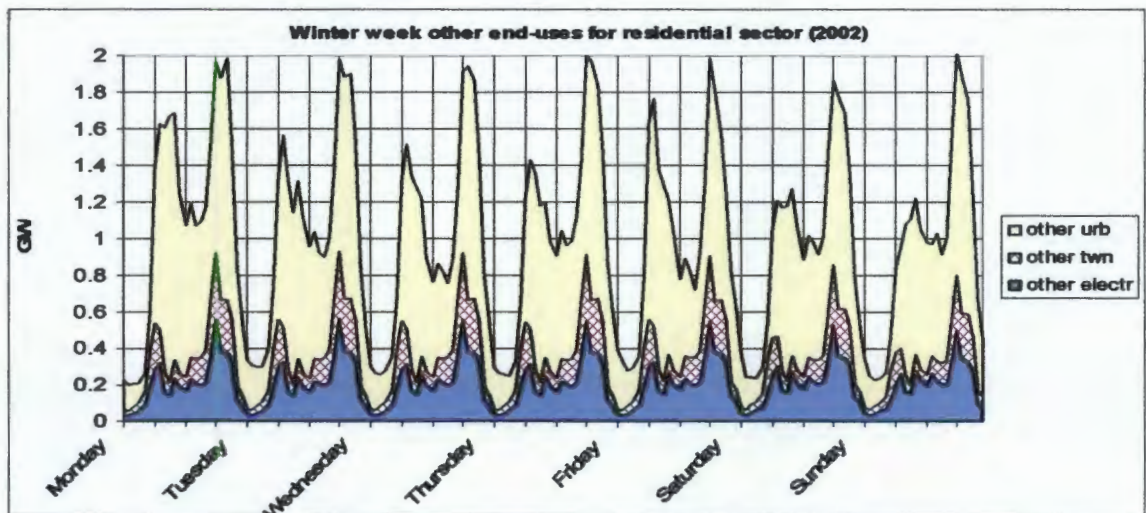


Figure 3-7 Residential other end-uses weekly winter load profile 2002

The use of electricity for other end-uses is the second most demanding after water heating. There is a peak of 1.8 GW to 2 GW between 18:00 and 20:00 on winter weekdays. The

morning peak varies more than the evening peak from 1.2 GW to 1.75 GW between 6:00 and 11:00. There is a 65% reduction in both evening and morning peaks in summer weeks.

3.2.1.4.1 Energy efficient practices

Due to the many load types used, a dedicated load program aimed at one end-use is unlikely and a program for efficient utilisation of many appliances is preferred. Turning appliances off when not in use can achieve savings but because of the relatively low cost of electricity, the incentive is small. Electricity prices and household income have a direct impact in the adoption of lower wastage behaviour. Information campaigns spell out how energy savings can be achieved by changing appliance usage techniques. The practices are usually simple but may take time to become standard practices. Awareness about the usage of each appliance improves efficiency by minimising wasted energy.

3.2.1.5 Residential cooking

Electrical loads used for cooking are hot plates, stoves, ovens and microwaves. The use of kettles is not included under cooking but rather with other plug points in the other end-use category. Urban households use all types of electric cooking whereas townships and electrification mainly used hot plate cookers. The electrification program aimed to change the energy usage of low income households to be more environmentally safe. Wood burning and paraffin stoves posed a health and fire risk. Uptake of electricity for cooking has been slow due to the costs of electricity which are a burden to low income households and the environmental and health benefits have not been fully realised. A weekly load profile for residential cooking is shown in the figure below.

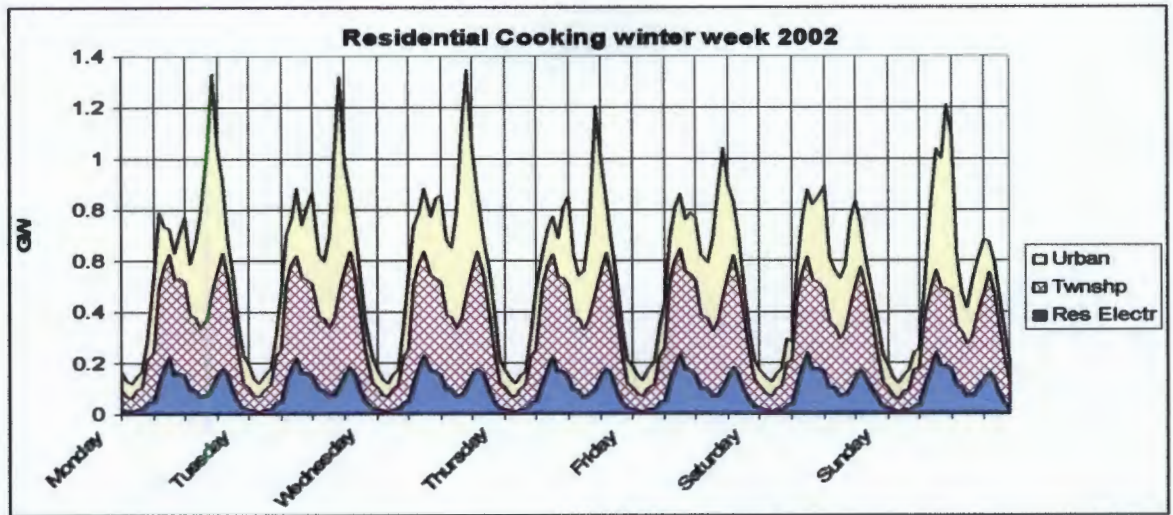


Figure 3-8 Residential cooking weekly winter load profile 2002

The national residential cooking load for a winter week is shown in the figure. The peak demand of 1.3 GW occurs at 17:00 on Monday, Tuesday and Wednesday. Urban cooking has an evening peak during weekdays but a morning peak on weekends. Township and electrification cooking have peaks in the morning and evening. The magnitude of electrification peaks are about 50% of township peaks. Urban residential cooking has a low morning peak of 200MW which is similar to that of electrification cooking but the evening peak for urban cooking is over 800MW on some weekdays. The load factor for urban cooking load is 0.22 which is lower than electrification and township cooking. It is worthwhile noting that there is a large Sunday peak from 10:00 to 11:30. This weekend peak was also found in the residential profiles for Cape Town in Appendix A.

3.2.1.5.1 Fuel switching to gas

The large evening peak can be reduced by fuel switching to gas for cooking in urban households such as is done by Egoli gas that reticulates gas to residential customers in the Johannesburg area. Currently, Johannesburg is the only city with complete access to piped natural gas. There has been a recent drive to use gas as a result of a network change-over from using hydrogen-rich gas from coal to liquid activities to using imported natural gas from Mozambique. The potential for other cities to distribute gas to domestic customers will depend on the gas availability and the gas utilisation by industrial and commercial users as they are the main users of gas. LPG could be used instead of natural gas. The main opportunity for LPG is for rural unelectrified households (still to be electrified) not urban households. The barriers to entry are the cost of the fuel and the accessibility to gas

appliances and cylinders. Other residential uses for gas are water heaters, space heaters and cooling but their utilization will depend on the price comparison between electricity and gas. A DSM program could promote the use of gas if the load reductions are obtained at a competitive cost to electricity supplies.

3.2.1.5.2 Cooking awareness

The NIRP allocates a reduction target of 1.34 MW/year and 3.44 GWh/year for cooking awareness [NIRP 2003]. Simple measures such as placing lids on pots can conserve heat. Education and awareness programs though information dissemination will be needed to improve cooking practices.

3.2.1.6 Residential cooling

Appliances such as refrigerators and freezers are mostly used by urban households although electrification customers also contribute significantly to the national residential cooling load.

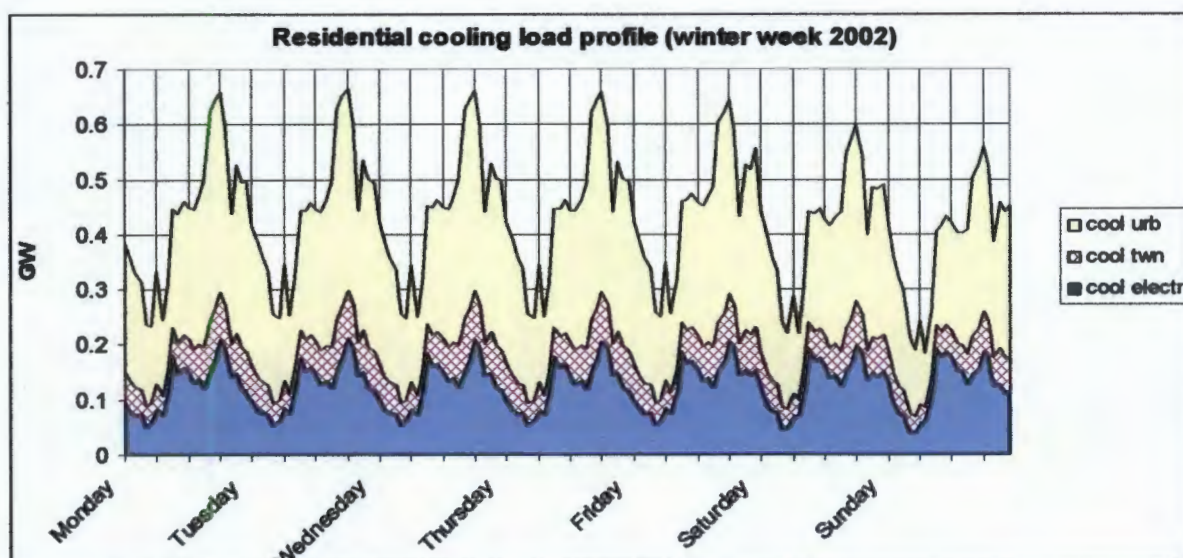


Figure 3-9 Residential cooling weekly winter load profile 2002

The total cooling load profile is more constant than other residential loads as refrigerators work on a thermostat. There are still pronounced peaks from all residential groups at 18:00 on winter days. The total peak demand is 0.65 GW for winter days. The maximum peak demand for cooling occurs during summer months as the ambient temperatures are higher

and the refrigerator is on more often. The maximum peak demand for summer weeks is 0.81 GW and the profile shape is the same as for winter weeks.

3.2.1.6.1 Efficiency through appliance standards and labelling

Much attention has been placed on the adoption of appliance standards and labelling for cooling loads [De Villiers et al 2000] as well as all household appliances [DME 2003¹⁶]. The standards and labels could be separate programs with the common aim of promoting efficient appliance use. A consumer's decision at appliance purchase should be motivated by energy labels as the extra cost for the higher efficiency appliance is recovered through energy savings through the equipment life.

3.2.2 End-use profiles for commercial and industrial customers and DSM opportunities.

The range of activities in commerce and industry combine electrical end uses from sectors such as: iron and steel, chemical and petrochemicals, non-ferrous metals, non-metallic minerals, gold mining, platinum and other mining, food and tobacco, pulp and paper, other manufacturing, commercial and public buildings, general services and agriculture. A DSM program would have to be designed according to the specific load utilised in each category. Similar end-uses are grouped to investigate the potential benefits from technology-specific electricity use. The electrical end-use categories are:

- High temperature heat and electrochemical processes
- Motive and material processing and handling
- Lighting
- Pumping
- Compressed air
- Heating, ventilation and cooling
- Fans
- Industrial cooling
- Homes and hostels

¹⁶ Draft energy efficiency strategy for the Republic of South Africa

Electricity is supplied to large electricity consumers such as municipalities, mining and metals processors directly from the transmission network. Smaller electricity consumers in industry, commerce and the residential sector are supplied by distributors who purchase bulk electricity from the transmission network operated by Eskom. Tariff structures that reflect the costs of supply at different times are used for bulk purchasing of electricity. Generally, commercial and industrial loads have load factors ranging from 0.5 to 0.9 as was shown in section 1. Electricity consumption is large as loads operate at constant levels throughout the year. Energy efficient equipment could therefore produce substantial savings and be paid off quickly.

Electricity use by industry is large and appropriate tariff structures which can reduce peak demand are a vital demand based resource. Electricity is charged with an energy component (kWh) and a demand component (kW or kVA). The energy demand component is charged by measuring the maximum demand at half hour intervals so turning loads on at different times would reduce the maximum demand costs. The energy component for a time-of-use (TOU) tariff consists of different rates for peak, standard and off-peak electricity use. TOU and maximum demand charges require the appropriate meters to measure electricity use at different times and the maximum demand.

Customers adopt a TOU tariff to reduce their electricity costs. The timing of processes based on tariffs could further reduce electricity costs for the consumer if production is not adversely affected. The fixed times for the TOU tariff reflects the costs of supply and a seasonal difference can be added to the tariff structure such as used by the Eskom's Megaflex tariff. Time periods reflect the average peak demand but a larger customer response would be possible with exposure to market based short-term pricing signals through real-time pricing [Surtees 2003]. Continuous communication between the utility and the consumer indicates the real cost, depending on current supply and demand conditions. The consumer should have sufficient flexibility in process selection to maximise electricity usage at times of low electricity prices. It is estimated that TOU tariffs resulted in over 100 MW of load shifting in 2003 with only 2 major customers participating [Surtees 2002].

The demand side can compete to provide a reserve market for the utility with interruptible load agreements. There are three categories in such agreements [Surtees 2003].

1. Instantaneous load reduction where a customer respond within 10 seconds of an under frequency event and sustains the reduction for up to 10 minutes afterwards.
2. Customers respond within 10 minutes when requested and maintain reduction for up to two hours afterwards.
3. Supplementary reserves maintain reduction from the time an incident occurs until the new generation shift.

Customers with interruptible load agreements are paid for the availability of the reserve whether it is used or not. The reserve market improves the network's operation and stability as loads can be reduced during supply shortages. There is a target to have 1.510 GW of interruptible load available up to 2008 which diminishes to 0.384GW by 2016 [NIRP 2003]¹⁷.

Load profiles of industrial and commercial electrical end-use provide insight into the likely effects of DSM programs.

3.2.2.1 High temperature heat and electrochemical processes

Most industrial sectors require electricity for high temperature heating or electrochemical processes. Electric boilers, dryers, arc furnaces and smelters are examples of heating loads. The contributions to the total electrical heating load winter profile from various sectors are shown in the figure below.

¹⁷ National Integrated Resource Plan 2003/2004 Appendix 2 page 3

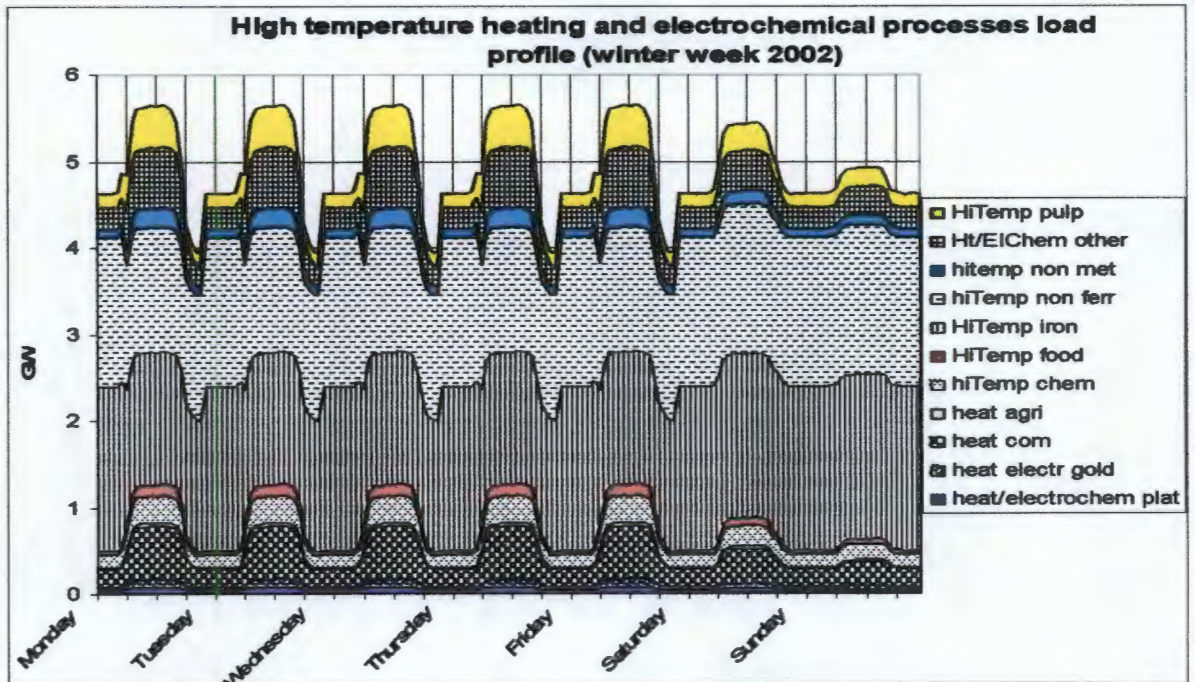


Figure 3-10 High temperature heating winter weekly load profile by sector 2002

Heating applications in industry are the single most demanding end-use. The flat weekday peak of 5.6 GW occurs between 7:00 and 15:00. The largest loads are for base metals production with a combined peak demand of 3.6 GW that occur on weekdays between 22:00 and 4:00. The effects of time-of-use tariffs and real-time pricing arrangements with base metals producers are indicated by the load reduction during weekday hours of 6:00 and 20:00. Iron and steel heating loads are reduced by approximately 400 MW and non-ferrous metals electrolytic loads by 300 MW. No reductions occur on weekends as they are off peak periods. The heating loads for the remaining sectors have a constant demand of 1 GW but a peak of 2.65 GW.

3.2.2.1.1 Energy efficient practices

Heat recovery from some processes could provide heating to other processes using heat pumps. The overall energy efficiency for the system would increase as less direct heating is used. Insulation of hot surfaces reduces energy losses. Even though heat recovery systems are usually installed with the initial process, there may be new opportunities as processes are expanded.

Fuel switching is possible with heating loads and can replace electric heating depending on their costs, efficiency, availability and performance within a process. Cogeneration of heat

and power may also be possible if a feedstock is available. Sugar refineries and wood mills use by-products to generate heat and/or electricity. Natural gas has become available for use in the Johannesburg region and could reduce electricity costs if gas fired heating is cost effective for industrial processes.

3.2.2.2 Motive and material processing and handling

Motors are required to move large amounts of material from place to place as well as to process materials with crushers, mills, rollers and other machinery. All industrial sectors use significant electric motor loads for processing and manufacturing and the weekly load profile is shown in the figure below.

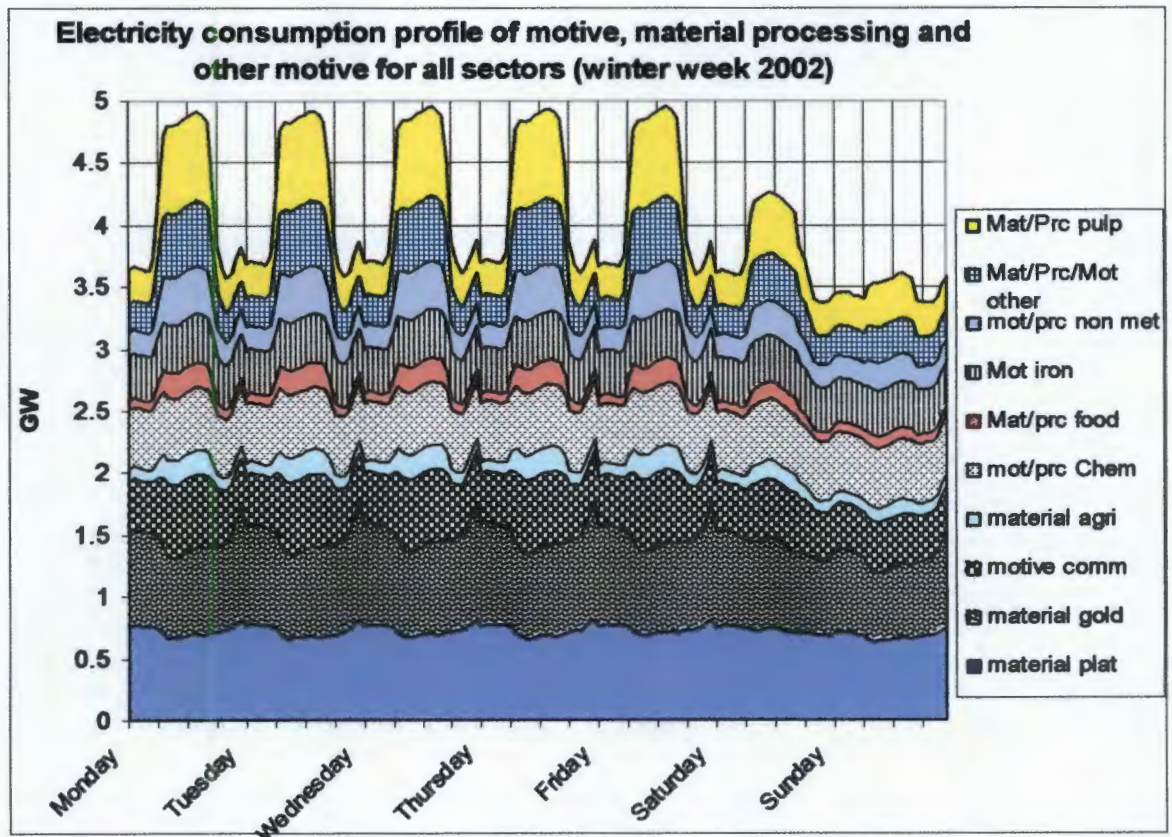


Figure 3-11 Motive winter weekly load profile by sector 2002

The use of motors for material processing and handling has the highest electricity demand after heating applications. A peak of 5.8 GW to 5.95 GW occurs during the weekday hours of 7:00 and 15:00. There is a constant load of approximately 3.5 GW throughout winter weeks. The cause for the 1.45 GW rise is mainly from industries such as agriculture, other

manufacturing and paper and printing that consist of many smaller operations working on a single weekday shift. Large industries are automated to a higher level and have a more constant demand for motive power as processes can be run at night.

Motive power for gold, platinum and other mining demands 1.6 GW between 24:00 and 6:00 during weekdays. There is a sharp peak of 1.7 GW at 22:00 on weekdays that is caused by load shifting from peak times occurring earlier in the day. A reduction of 300 MW to 400 MW from peak loads occurs during the weekday hours of 7:00 to 19:00. The remaining sectors, besides iron and chemicals, which are constant, operate more motor loads during 6:00 and 18:00 than at other times. The use of motors by the commercial sector is high due to uses such as hoisting, conveying, pumping and air circulation being included in the sector whereas for industrial sectors they are categorised separately.

3.2.2.2.1 Demand based resources

The NIRP stipulates energy efficient targets for motive loads to be achieved with variable speed drives (VSD), replacing and upgrading of existing motors [NIRP 2003]. The targets for commercial and industrial motor loads are shown in Table 3.2.

<i>EE option</i>	Commercial		Industry and Mining	
	MW/a	GWh/a	MW/a	GWh/a
<i>VSD</i>	0.26	1.9	4.4	29.3
<i>Replace</i>	0.68	3.5	1.13	7.72
<i>Upgrade</i>	0.66	3.4	1.06	7.02

Table 3-2 Targets for energy efficiency motors

Due to selection criteria, most motors operate between 60% and 80% of full load but many motors will run at lower load factors [Peterkin 2003]. Energy efficient motors aim at reducing losses which are constant during operation and those dependent on load. Efficiency improvements can amount to 10% at low loads (25%) and 3 to 5% at full load.

3.2.2.3 Lighting

Lighting is required by most activities indoors such as offices, factories, warehouses and underground mining and by some outdoor applications such as street and premises lighting. The total load profile for lighting, in each industrial and commercial sector, is illustrated in the figure below.

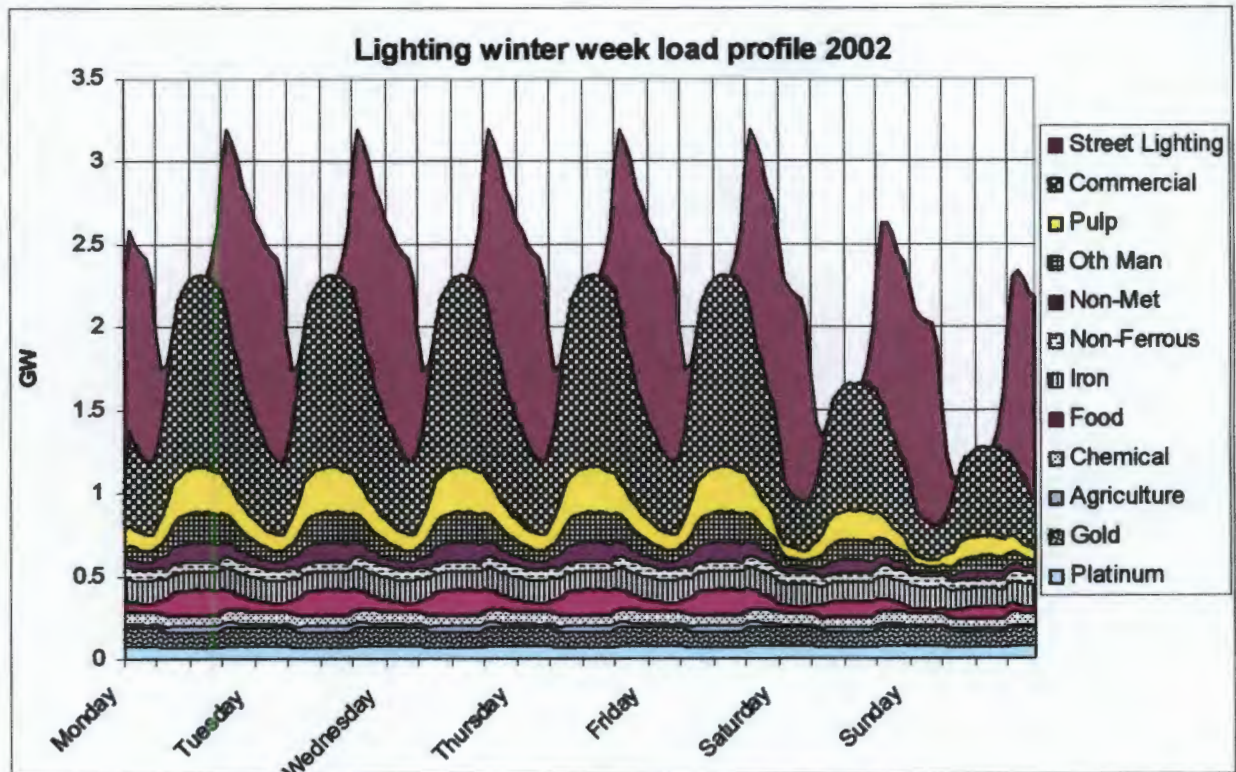


Figure 3-12 Lighting winter weekly load profile by sector 2002

The national demand for lighting in commerce and industry peaks at 3.2GW on 18:00 during weekdays. The load is reduced on weekends due to many facilities being closed. Lighting for the residential sector is dealt with earlier with other residential loads. The load profile for national street lighting occurs daily and has a flat peak of 1.22GW during night-time hours. It is assumed that all street lights are turned off between 7:00 and 15:00 during winter. Commercial lighting peaks during weekdays at 1.24 GW between 12:00 and 15:00 but 36% of the total demand is always on. There is an overlap between street lights turning on and commercial lights turning off which is the major cause of the peak experienced at 18:00.

Lighting for the combined industrial sector has a 1.19 GW weekday peak at similar times to commercial lighting peaks. There is a reduction to 76% of the weekday peak on Saturdays and to 64% of the weekday peak on Sundays. The large single industries such as mining, chemicals and base metals production have a more constant load than large multiple industries such as other manufacturing, pulp, paper and printing and non-metallic minerals processing. The total demand is reduced by 15% in summer months as the night-times hours are less.

3.2.2.3.1 Energy efficient lighting

Replacing magnetic ballasts with electronic ones is a common energy efficient practice in industrial lighting. Appropriate lighting levels should be maintained by selecting the most suitable lighting technology for the application. Efficient bulbs can be chosen if they are available for the application. Installation of lighting controls could reduce usage as no manual effort is needed. The NIRP's commercial energy efficiency targets are the highest for lighting with an annual load reduction of 9.53MW. Industrial targets are 3.77 MW per year.

3.2.2.4 Heating, ventilation and cooling

Heating ventilation and cooling (air conditioning) is required to regulate the working environment in offices and factories. The national winter weekly electricity demand for HVAC is shown in the end-use load profile below.

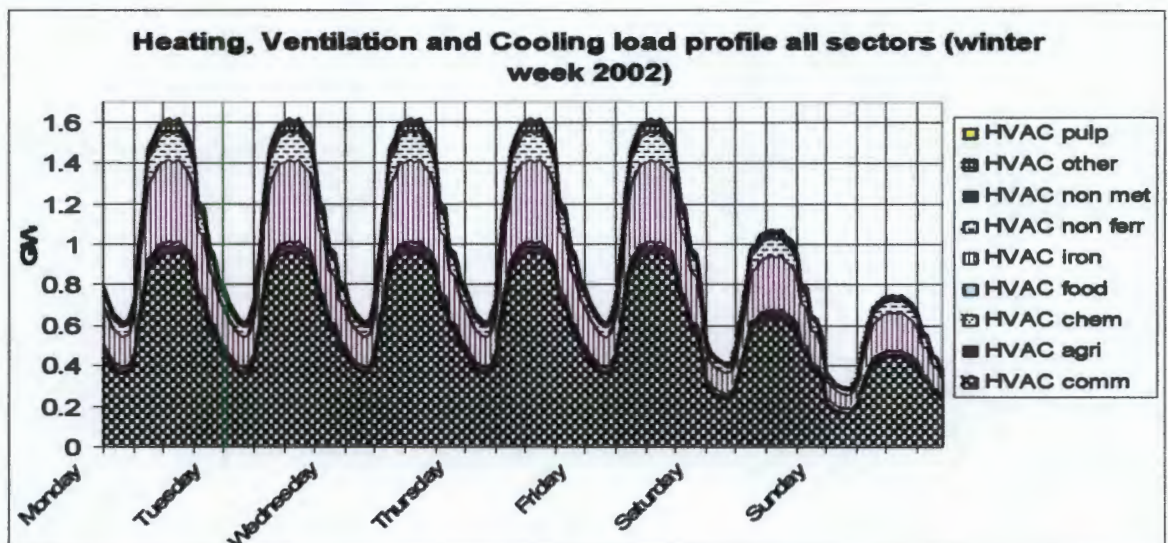


Figure 3-13 HVAC winter weekly load profile by sector 2002

The national demand for heating, ventilating and cooling is 1.6 GW from 11:00 to 15:00 on winter weekdays. The main use of HVAC equipment is by the commercial sector accounting for about 60% of the national use. The peak of 0.95 GW for commercial HVAC drops to 0.8 GW during March when the least HVAC is needed. Over 40% of the HVAC load occurs during 24:00 and 6:00 indicating the continuous operation of HVAC equipment. Base metals production also uses significant HVAC equipment and contributes 550 MW to the national load peak.

3.2.2.4.1 Energy efficient use

Effective control over HVAC equipment could regulate the temperature indoors compared to the ambient temperature outside thereby increasing comfort and optimising energy performance.

3.2.2.5 Compressed air

Pneumatic tools and machines are used for a wide range of activities; such as drilling for mining, spray painting of vehicles, pressing of moulds and other applications. Compressed air is used by most industrial sectors as is shown in the national weekly load profile below.

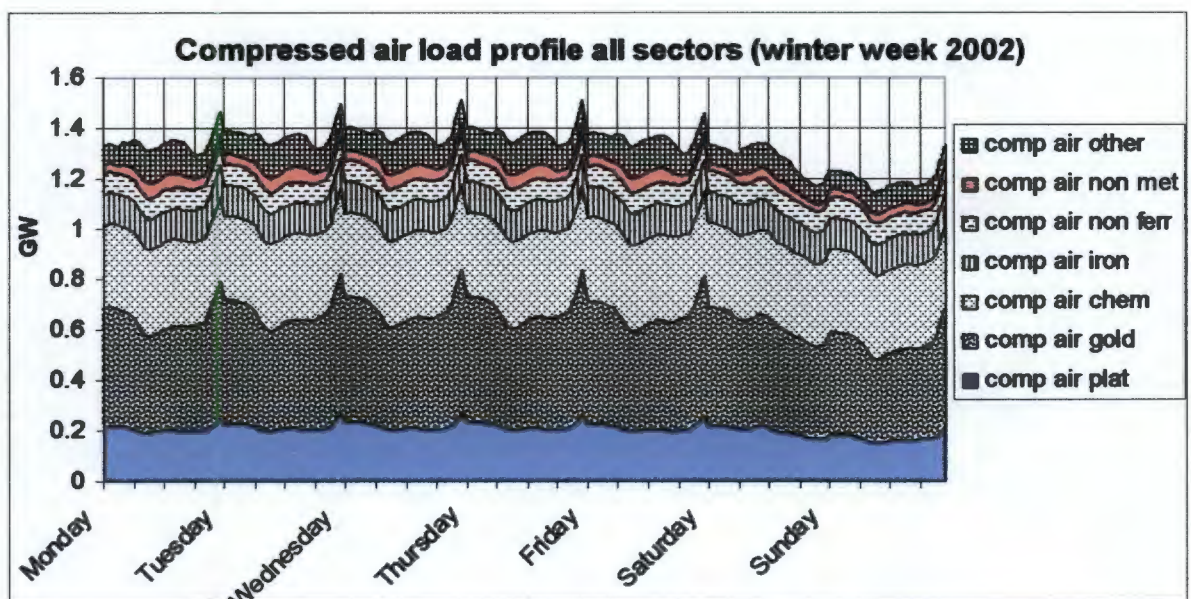


Figure 3-14 Compressed air winter weekly load profile by sector 2002

The national load profile of electricity used for compressed air is very constant as its main users are large industries that operate on 24 hour cycles. A 100 MW sharp peak is experienced at 23:00 during weekdays bringing the total peak to 1.5 GW. The peak is caused by gold mining activities that have shed their compressed air load to off peak periods and the increased use is the response to lower activity during earlier hours. All compressors in mining activities demand a total of 0.8 GW for one hour and a constant load of 0.6 GW. Compressed air for other industrial sectors makes up over 50% of the remaining load of which chemicals and petrochemicals is the largest contributor. Compressed air loads for industry are essentially constant as large central units supply compressed air for many activities. The load for other manufacturing fluctuates more as compressed air operations are increased during commercial working hours of 7:00 to 17:00.

3.2.2.5.1 Energy efficiency

Reducing leaks in compressed air piping and tools can amount to significant energy savings. Storage of compressed air may be cost effective if the use is intermittent and smaller compressors could be operated at higher loads.

3.2.2.6 Pumping

Pumps are used to move slurries for mining activities, water for farming and a range of chemicals, liquids and coolants in other industrial processes. All industrial sectors use pumps and patterns of use vary across each sector as is shown in the figure below.

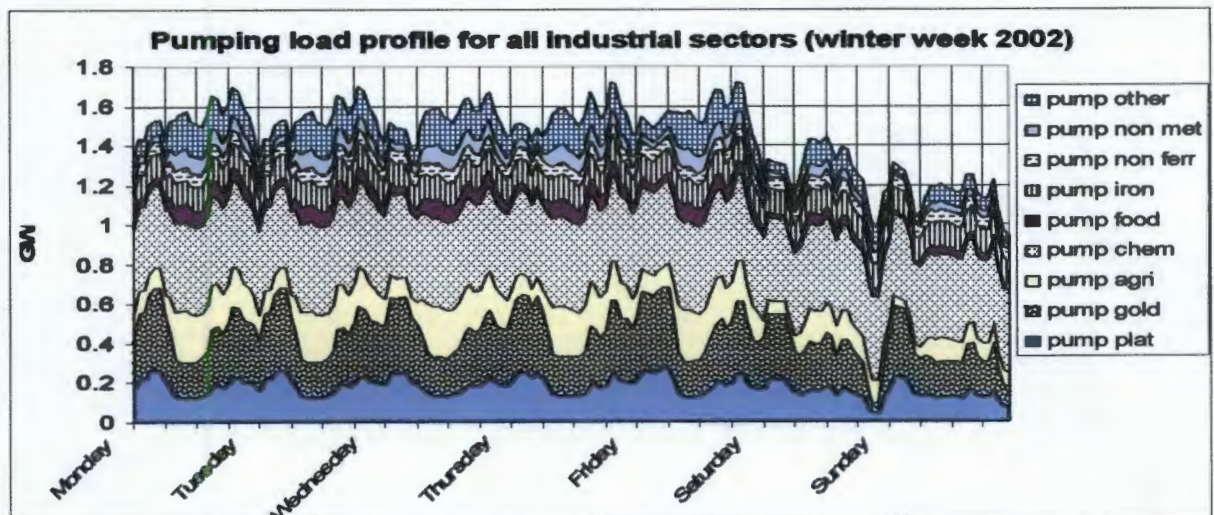


Figure 3-15 Pumping winter weekly load profile by sector 2002

The use of electricity for pumping peaks between 19:00 and 20:00 during winter weekdays at a peak load of 1.7 GW. The total demand is increased by 12% to 1.9 GW during summer months caused by increased demand for pumping by gold mining resulting in a slightly flatter total load profile. The total weekday variation is 300 MW and is increased to 700 MW on weekend nights. There is a 50% variation in pumping demand for mining activity daily. A peak of 700 MW occurs for mining between 3:00 and 6:00 and there is also reduced peak between 20:00 and 21:00 on weekdays. Pumping for agriculture occurs mainly during the hours of 6:00 to 23:00 with a 240MW peak from 8:00 to 9:00 on weekdays. Chemicals and petrochemicals utilize 400 MW of electric pumps on a constant basis. The remaining industries use 550MW of electric pumping capacity at 9:00 on weekdays which is reduced by 60 MW by 18:00 and by a further 130 MW by 2:00 the following morning. The constant loads of the chemicals industry and only slight secondary peak load reduction by the other sectors, especially mining, is the cause for the peak at 19:00.

3.2.2.6.1 Demand side management

Shifting of pumping loads to off-peak times may be possible if the liquids are to be stored and not vital to immediate processing requirements.

3.2.2.7 Fans

Fans are used to produce a draught and cool processes or environments by air flow. Electric fans are used by all industrial sectors as is shown in the figure below.

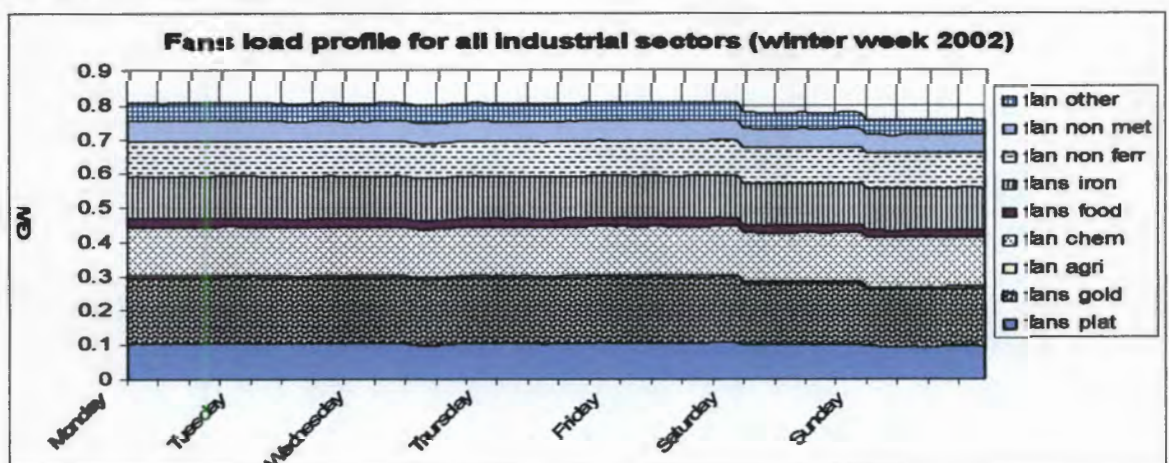


Figure 3-16 Electric fans winter weekly load profile by sector 2002

Fans for ventilation and other uses are the most constant loads in industry and collectively demand 800 MW almost all of the time throughout the year. Fans for mining account for 38% of the national industrial fan load. Fans for base metals production and chemicals processing account for 29% and 18% of the total fan load respectively. In reality the profile shape for fans may not be as constant as not all industries operate on 24 hour cycle and there may be daily peaks coincident with day-time working hours.

3.2.2.7.1 Energy efficiency

Fans operate on the most constant loads and efficiency improvements through equipment replacements have quicker payback periods than for other loads. The NIRP targets 0.64 MW/a for fans and pumps capacity reduction in the commercial sector and 1.31 MW/a in the industrial sector.

3.2.2.8 Industrial cooling

Large refrigeration is required to cool air in deep level mining and store perishable foods. Not all industries require electric cooling as is shown in the figure below.

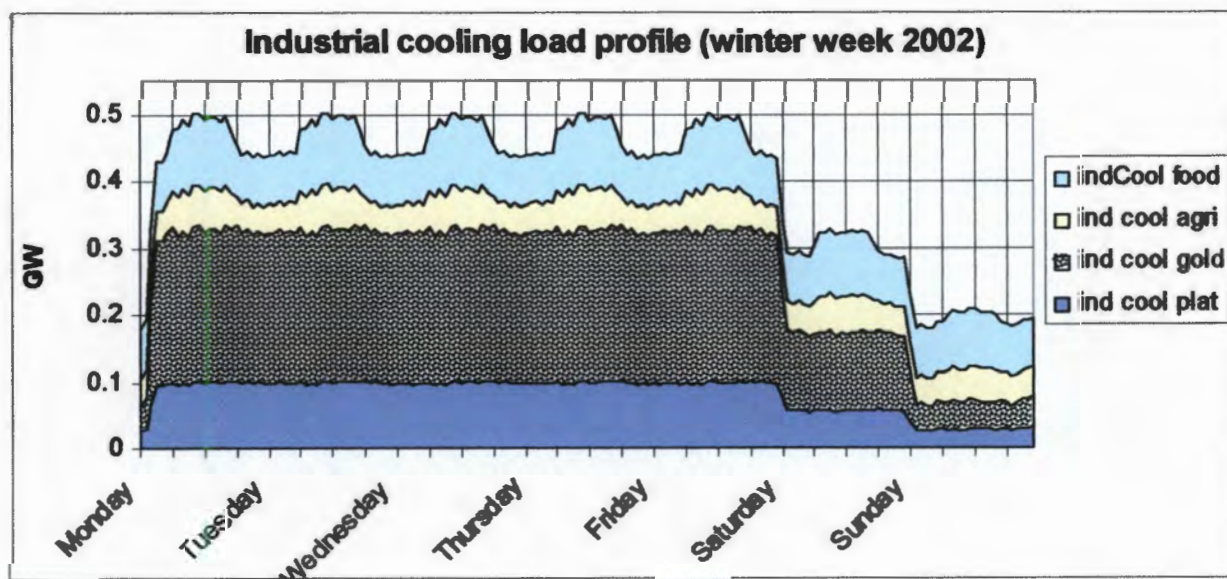


Figure 3-17 Industrial cooling winter weekly load profile by sector 2002

The use of industrial cooling is dominated by the mining sector to cool air for deep mining activity. There is a constant load of 330 MW during the week from gold, platinum and other mining which drops to 180 MW on Saturday and 80 MW on Sunday. Food processing and agriculture account for 260 MW of industrial cooling load for food refrigeration. The daily profile is constant for industrial cooling by food and agriculture with the peak load between 7:00 and 15:00 and a reduced load of 42% at other times.

3.2.2.9 Homes and hostels

Residences are needed for miners, farmers and workers in commerce related activities. These residences are located nearby industries and have been included with the industrial sector instead of the residential sector. The load profile shape for such residences are similar to other residential loads as can be seen with the distinct morning and evening peaks in the figure below.

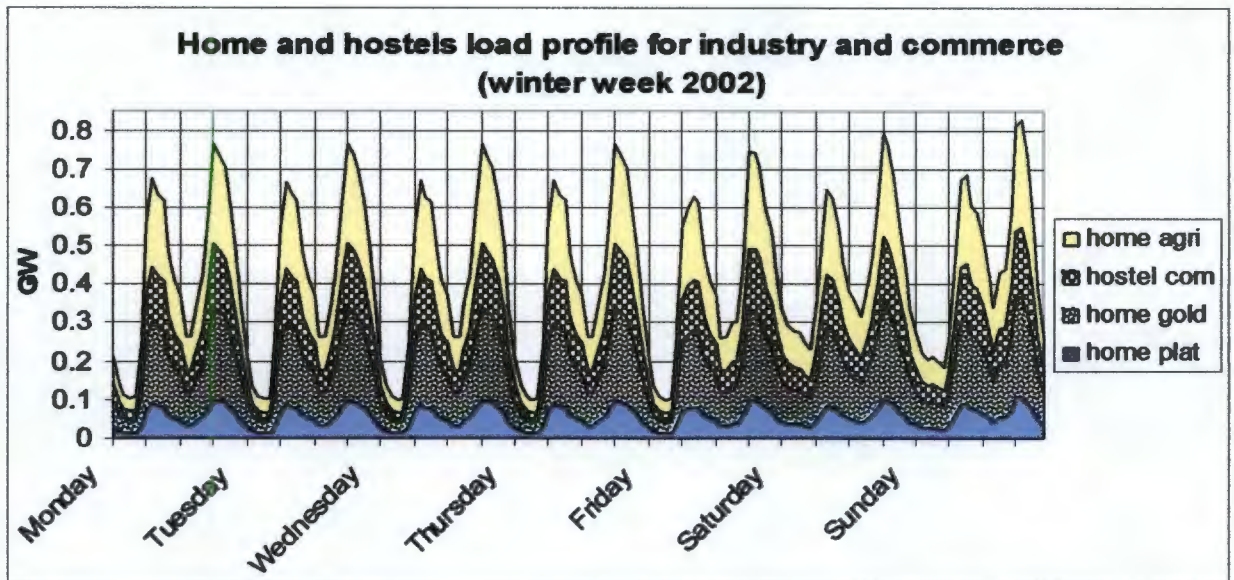


Figure 3-18 Homes and hostels (for industry and commerce) winter weekly load profile by sector 2002

The total load requirements for all homes and hostels for mining, agriculture and commerce was 810 MW in 2002. The load includes all cooking, space heating, refrigeration, lighting water heating and other appliances such as televisions and radios. The load is fully used on winter weekend evening between 18:00 and 19:00. The winter weekday peak is slightly reduced at 760 MW at the same daily hour. There is also a morning peak about 85% of the

evening peak. Hostels for gold mine workers accounts for 32% of the total peak load, hostels for platinum and other mining 12%, residences for commercial 20% and 36% for farm homes and hostels. The peak load is reduced in summer months by 30% of the maximum winter peak as less water heating and no space heating is required.

3.2.2.9.1 Demand resources

The DSM and EE measures mentioned for residential loads could also be introduced into the homes and hostels in commerce and industry. Electricity is usually supplied to hostels from common feeders to industrial loads and can affect the maximum demand or selection of tariff structures.

3.2.3 Combined demand resources

The nine year investment plan in the NIRP targets a total 153 MW to be displaced every year [NIRP 2003]. Energy efficiency measures aim to reduce 62 MW which is equivalent to approximately 300 GWh saved each year. Load management, excluding interruptible supply arrangements, have targeted 100 MW annual shifting. Eskom has budgeted R350 million in 2003 to meet the DSM targets, as in 2003, although there is currently under utilisation of these funds [Franz 2004]. By 2012, 1370 MW could be displaced and some maintenance will be needed during following years to ensure no deterioration of the displaced capacity.

There is uncertainty about the realisable capacity reduction in the future. Eskom estimates that a 4 255 MW reduction in 25 years [Stanford 2005]. The draft energy efficiency strategy report of the DME [DME 2003] mentions a 7.3 GW reduction by 2015 which will only be possible with increased DSM involvement above current plans. The total peak reduction target of 7.3GW is comprised of 3.2GW from interruptible load agreements, 1.6GW from load shifting and 2.5GW from energy efficiency [Surtees 1997]. A general energy reduction target of 12% by 2014 of forecasted consumption levels in that year is expected from all energy carriers. Electricity energy efficiency can contribute to this target. NIRP targets 2700 GWh for savings by 2012 from various programs mention previously. This reduction only represents about 1% of the total 12% target. If electricity is to contribute more to the target, more energy efficiency programs are needed for electricity use.

Two scenarios can be analysed, a conservation DSM strategy such as in the NIRP and a higher DSM involvement which considers further EE programs, higher penetration of load management and fuel switching measures as mentioned previously. The scenarios are integrated into an electricity plan, in a latter section, to determine their affect to the system and supply expansion plan. Load characteristic changes from DSM options can only be valued against supply options. Supply planning is required initially so that demand resources can be integrated into the plan.

4 Electricity supply in South Africa

In an integrated resource plan the demand for an energy service is met with supply capacity and demand resources. DSM and energy efficiency measures influence the demand so that the most cost effective integrated plan is found. The selection of demand resources can only be conducted once the costs of supply, both existing and future, have been calculated. Existing plants only have energy costs as they are already built. The future supply costs would have both energy and capacity cost components. Traditional supply side planning meets the projected demand using a least-cost approach. Each new supply option is compared on its cost and performance using screening curves. The least-cost supply options compete in supplying base load and peak load. The transmission and distribution costs are added to the production costs and the losses have to be accounted for by increasing supplies. Environmental concerns are playing a more important role in energy planning and regulations on emissions could result in increased expenditure.

A complete supply plan includes all existing generation baseload and peaking capacity and the possible technologies for system expansion. Electricity generation for South Africa is characterised by the energy resource such as coal, nuclear, gas, hydro and pumped storage. Performances and costing of power stations are sourced from previous electricity plans and energy statistics. The supply plan considers a diversification of supply capacity technology. New technologies for South Africa such as fluidised bed combustion, single and combined cycle gas turbines using gas and the pebble bed modular reactor form part of the expansion plan.

4.1 Existing power generation

South Africa has a developed electricity supply industry with 43 034 MW of licensed generation capacity in 2002 [NER 2002]. The maximum capacity available was 40 444 MW as there is some capacity in storage. The total electricity sent out by all generators was 206 523 GWh in 2002. The load factor for all generators was 54.8% in 2002 [NER 2002]. The low load factor indicates that the power stations are under utilised. The generation mix is mostly base load capacity which responds slowly to peak variations and stations are run at

low load levels. The reserve margin in 2002 was 17% [Eskom 2003] and constant supplies can be maintained even with large power station outages.

Eskom operates 95.8% of the generation capacity whilst 3.5% is generated privately and 0.7% by municipalities. The growth of the electricity industry was in response to mining activities such as gold and diamond mining. Deep mining is electricity intensive and South Africa has some of the world's deepest mines. Low cost electricity supplies were made possible by building large coal-fired power stations which burn cheap coal and are located near coal mines to reduce transportation costs. Mining and large industrial activities have more constant loads than small industrial, commercial or residential loads. The construction of large coal-fired power stations was in response to growth for constant loads. There is a lack of peak load capacity as there has been high peak demand growth. Peak demand will exceed capacity by 2007 and base load shortly after 2010.

Power generation technologies consist mostly of coal with 17 stations supplying 92% of electricity in 2002. Eskom operates a nuclear pressurized water reactor at Koeberg that supplies 5.8% of electricity (1800MW net capacity). There are 10 hydroelectric stations that generate 1.2% of the national's electricity. Gas turbines, used for peaking, run on kerosene (aviation fuel) contribute less than 0.1% to the electricity supply. Electricity generation from bagasse, a by-product from sugar refineries, amounts to 0.15% and is operated privately mostly by Tongaat Hulett. Pump storage hydroelectric schemes consume 1.4% of all generated electricity and provide 1% of national generation capacity in the form of peak load supply (1400 MW total capacity). There are small contributions from wind turbines and other renewable energy resources.

4.1.1 Coal-based electricity

South Africa has large reserves of coal situated in the North East. The coal is low grade bituminous coal and is mined in open cast or in low and deep level underground mines. The coal used in power stations has a calorific value of between 19 and 22 GJ/ton and the cost per ton of coal ranges from \$6.5 to \$13.9 [Cape Power Project, Kudu Gas]. There is a total of 24 435 million tons of power generation grade coal reserves from coalfields in Witbank, Mpumalanga, Vereeniging/Sasolburg, Highveld and Waterberg [Cape Power Project, Kudu Gas].

Most large power stations are located nearby collieries to reduce the cost of transportation and the electricity is transmitted instead using high voltage transmission lines. The provision of bulk electricity at a low price and the high grades of gold ore allowed the mining activities to be very profitable. The high growth from mining resulted in large investments in coal fired power stations. South Africa built some of the largest coal power stations in the world. Kendal, with a nominal capacity of 4.1GW, is located in Witbank and its sixth unit was commissioned in 1993. The most recent commissioned power station is Majuba located at Volksrust with a 3.8 GW net maximum capacity brought into service between 1996 and 2001 [Cape Power Project, Kudu Gas].

Eskom operates 10 coal stations with a total net maximum capacity of 32 GW. The life of each station is 40 years from commissioning. There are 3 stations, Camden, Grootvlei and Komati that are mothballed and have a total reserve storage capacity of 3.5GW. The stations Hendrina and Arnot were commissioned in the early 1970's. Most stations were commissioned between 1980 and 1995 and consist of 6 units of approximately 600 MW each. Not all the generation capacity could be utilised and some stations were taken out of service. Reserve storage reached its peak of 4500 MW in 1993. The surplus capacities of the 1990's were as a result of a drop in economic growth rate of the country.

Each station has a planned outage of 28 days and a forced outage of 18 days for maintenance and repairs. The efficiencies range from 33 % for the older stations to 37% for the newer stations. Kendal, Matimba and half the units in Majuba use dry air cooling and their total station efficiency is slightly lower at 34% -35%. Matimba is the world's largest direct dry cooled power station where the steam from the 6 units of 665MW is condensed by a forced draught radiator-type heat exchanger into water and returned to the boiler [Spencer Jones 2001]. The average usage of water in dry cooling is 0.2l/kWh whereas for wet cooling 2.5l/kWh. The choice of the level of dry versus wet cooling will depend on the availability of water and the costs of the extra equipment compared to the cost of the added coal due to lower efficiency. The other 3 generator units at Majuba use wet cooling and achieve 37.6% efficiency but the fuel costs for Majuba are the highest compared to other Eskom coal fired stations because of the coal that has to be transported from Matla power station. On average, each kWh of electricity produced needs approximately 0.49kg of coal and 1.27l of water [Eskom 2003]. All Eskom's coal power stations except Majuba supply base load power to

the transmission network. The total load factor for the 10 coal fired power station was 61% and the total sent out electricity 181 749 GWh in 2002 [NER 2002].

There are 4 municipal coal fired power stations that produced a maximum of 535MW of power in 2002. The total load factor for these stations was 25.6%. Private generation using coal occurs at Kelvin power station and two stations operated by Sasol. The maximum power produced was 1215 MW and a load factor of 65.3% was achieved [NER 2002].

4.1.2 Nuclear electricity generation

Eskom operates the continent's only nuclear power station, Koeberg 35km north of Cape Town. Due to the coal fields being mostly confined to the Highveld approximately 1500km from the Cape coast, it was feasible to build a nuclear station instead of transporting the coal or transmitting the electricity. Koeberg was fully commissioned by 1985 and consist of two pressurised water reactors rated at 900 MW each. Koeberg operated on a 70.8% load factor in 2002. Cooling water is provided by the sea and cooling towers are not needed thus saving investment costs and water utilisation. Koeberg helps in balancing and maintaining the 50Hz frequency on the large transmission network as it is far from the generation centre. In 2002, Koeberg supplied 11 962 GWh of electricity. The yearly planned and forced outage rate is 35 days and 7% respectively [Cape Power Project, Kudu Gas].

Rich uranium slurry is a by-product of gold mining operations in South Africa. NUFCOR has processing facilities to produce uranium oxide powder from the slurries. South Africa has 284kt of uranium which equates to 9.1% of world reserves in 2002 and a world ranking of four [DME 2003]. The Atomic Energy Board, now the South African Nuclear Energy Corporation (NECSA), was asked by Government to build local fuel enrichment and manufacture plants from fear of sanctions [IAEA 2002]. Fuel conversion, enrichment and fabrication have been stopped recently as the fuel could be obtained on the international market. The low and intermediate level radioactive waste is disposed of in metal drums and steel and concrete containers respectively at Vaalputs operated by NECSA. The spent fuel from the Koeberg reactors is stored on-site in pools of water for the 40 year life of the plant.

4.1.3 Hydroelectricity, pump storage and imported hydroelectricity

South Africa is a dry country with an average annual rainfall of 464mm compared to the world's average of 860mm [IAEA 2002]. There is a total licensed capacity of 668 MW of hydro electric stations of which 661 MW is attributed to Eskom and the remaining 4MW and 3MW to municipalities and private generation. The largest scheme is the at the Gariep dam which produced a maximum power of 365MW with a 36% load factor. Hydro power is able to respond quickly to load changes and is used for peak and intermediate loads.

Pump storage is used to provide peak load capacity and it can respond to quick load changes thus improving the performance of the total generation capacity. The benefits are mostly realised when there are many base load power stations and the demand has a low load factor. Water is pumped to top reservoirs during off-peak usage times and allowed to flow through turbines during peak times. South Africa has 3 pump storage schemes of which two are operated by Eskom namely, Drakensburg (1178MW) and Palmiet (486MW), and one owned by the City of Cape Town (CCT), Steenbras (174MW). The load factor for Eskom's pump storage operations was 12% whilst for CCT 18% indicating peak load supply. Total pump storage usage for 2002 was 2828 GWh for pumping operations and 2011 GWh for generation.

Eskom purchases electricity from Cahora Bassa, a hydro-electric power plant in Mozambique. There is a 533 kV DC transmission line to import the power 1000km into South Africa. The capacity is approximately 912MW [NIRP 2003¹⁸] and the total electricity purchases in 2002 was 9496 GWh [NER 2002].

4.1.4 Gas Turbines

South Africa has very little gas and oil reserves. There are currently 672 MW of licensed capacity for open cycle gas turbines of which half are operated by Eskom and half by municipalities. The turbines use kerosene for fuel has a high cost and the turbine usage is mainly for emergency and peak supply. In 2002 only 8 GWh were generated whilst 2 GWh were consumed to maintain the turbine operation.

¹⁸ National Integrated Resource Plan 2003/2004 appendix 1.

4.2 New Electricity Supply Options

4.2.1 New coal based electricity generation

Coal is set to remain the main energy resource for electricity generation in South Africa due to the abundant coal reserves. There are recoverable coal reserves of 55.333 billion tons and the annual production was 224 million tons in 1998 [Coakley 1998]. There is currently reserve storage that could be brought back into service. A total of 3500 MW of capacity can be commissioned from 3 stations. Camden with 1529MW (4 units of 380 MW) is being refurbished to resume operation in 2005. Grootvlei power station has a capacity of 1130 MW (3 units of 377MW) and is expected to be operational by 2007. Komati has 909 MW that could produce power by 2009. There is approximately 15 to 20 years of service life from each station. The cost of refurbishment is R4 billion that is to be spent between 2005 and 2011[Hill 2003].

There are plans to replace half the capacity at the Komati station with a fluidised bed boiler that could make use of discard coal [NIRP 2003]. There are large reserves of discard coal due to the massive coal activities. The grade of the coal is lower than that needed in current PF stations. Current pf technology can maintain performance with grade as low as 16GJ/ton before upgrading of blending the fuel such as is being done at Duvha power station. The calorific value of 13.93GJ/ton is used to calculate the performance of the FBC power station whilst there are grades of 9Gj/ton to 24Gj/ton in the reserves [Olsha et al 1997]. The stockpiles of discard coal were 55.2 million tons in 1996 [Olsha et al 1997]. These large reserves will increase every year until they are utilised by such technologies as FBC power stations.

Komati could provide valuable experience with the new technology as there are concerns about technical failure from incompatibility to the existing pulverised fuel equipment. It is estimated that over 5GW of capacity could be operated from current reserves [Olsha et al 1997]. The fluidised combustion bed is attained by circulating or bubbling air upwards to cause coal and other material to have more contact and combust more completely. The bed could be under atmospheric pressure or pressurised to reduce the boiler size. A FBC can provide steam to turbines using a wide grade of coal with high ash content. Another advantage is that sulphur can be removed from the coal during combustion thus avoiding the

costs of flue gas desulphurisation. A sorbent such as limestone, dolomite or calcite is introduced into the bed operating at 900°C. There are large amounts of waste slurry produced from the combustion bed that need to be disposed of. FBC is mature world wide and it could be a suitable technology for South African electricity generation.

Large coal fired pulverised fuel (PF) station technology has the benefit of being highly developed for use in South Africa. New stations could be built near mines. Site allocation is not flexible as costs for transportation of the coal would increase with distance from the mines. Clean coal technologies (CCT) are available at extra costs and can be fitted to new stations or retrofitted to old stations to meet regulations. CCT equipment includes filters and separators for particulate removal, flue gas desulphurisation and low NO_x burners. There is currently air pollution legislation in South Africa governing only emissions of particulates. World Bank standards govern other emission and new plants considered in this report adhere to these standards so flue gas desulphurisation (FGD) is added to the investment costs.

The costs and performance data was obtained from the NIRP for selected power stations and is shown in Table 4.1 with other generation options. New PF stations would typically be 6 units of 700MW of installed capacity with dry cooling and FGD. Dry cooling has the advantage of more site flexibility from less water constraints. The performance of the station is reduced and the water savings are large. Extra investment is needed for the air cooled radiators and there would be utilisation of electricity if the draught was produced by fans and not induced naturally by a tower.

There are world-wide environmental pressures for coal-fired generation to lessen its impact on air pollution and GHG emissions. Coal power stations in South Africa collectively emitted 190 million tons of carbon dioxide (CO₂) in 2003 [Eskom 2003]. It is possible to capture CO₂ through sequestration and the methods suitable for South Africa differ in technology and cost. The gas could be separated from other flue gases and the pure CO₂ stored. Underground storage in old mines would require geo-technical studies. CO₂ is absorbed for organic plant growth but there is not large potential for forestation projects in South Africa as it is a dry country. Less CO₂ could be generated by burning less coal. The efficiency of coal power stations could reach 46% through operating at supercritical steam condition (higher temperatures and pressures) but the advanced technology would have to be proven

commercially [Van de Riet et al 2003]. Investment in CCT technologies could be enhanced through international emissions trading mechanisms in the future.

4.2.2 New nuclear power

The benefits for the expanded use of nuclear energy in the South African power mix are:

- Past experience with nuclear reactor and fuel technology.
- No GHG emissions during operation
- Balancing national load by coastal siting and reduce transmission loading and costs.
- Potential to develop beneficiated uranium resources for energy fuel

There are added costs involved with nuclear energy compared to other thermal power stations. Elaborate safety procedures during construction and maintenance are ensured by monitoring and approval of external agencies. Extra investment is needed for radiation containment. There are various levels of nuclear waste disposal and decommissioning is more complicated to avoid any uncontrolled radiation leakage.

The structures are in place to develop South Africa nuclear capacity in generation and even fuel fabrication could be achievable. Capacity could be added with pressurised water reactors such as at Koeberg or advanced light water reactors [NIRP 2003].

There is local research into a new type of nuclear reactor, the pebble bed modular reactor (PBMR). The reactor works in theory and computer simulation but a demonstration plant is needed to confirm the technology for commercialisation. The reactor technology is a high-temperature reactor (HTR) that uses helium for cooling and graphite as a moderator [PBMR]. The PBMR can be built in modules of 165MW and additional modules added as the demand increases. There are inherently safety features as the peak temperature is limited if there is a loss of cooling and the reactor can cool off naturally from the heat dispersion to the structure. The core contains 380 000 fuel spheres which are each multi-layered with 9g of enriched uranium particles (8% U-235) embedded in various forms of carbon and 150 000 solid graphite spheres locating in the core centre. There are control rods and reserve shutdown units to absorb energy from the reactor. The mass flow rate of the helium through the core is increased to produce more power from the turbines. The efficiency of the PBMR is likely to

be 40% and higher efficiencies are possible with higher temperatures. The fuel will be sourced from Germany and NECSA has been approached to develop fuel manufacturing capability locally.

There is currently a demonstration PBMR being planned for construction on the site of the Koeberg power station. Environmental impact assessments are being conducted into four sites around the south-western Cape coast. A coastal location for the PBMR could use sea water for cooling and avoid the costs from cooling towers and use less water. The growth of the PBMR depends on the political reactions and public acceptance to new nuclear technology. The PBMR is included in the future generation supply plan and the costs and performance are tabulated with the other options.

4.2.3 New gas turbines for electricity generation

Natural gas could occupy a much larger share in South Africa's energy mix in the future. Imports of natural gas by pipeline and liquefied natural gas (LNG) by ships are being planned for electricity generation. Mozambiquean gas reserves from the Pande and Temane fields are 1.7 TCF and 1.4TCF respectively. A pipeline of 900 km has been constructed to supply gas to Sasol's liquefaction plant at Secunda and for distribution to Johannesburg by Egoli Gas. The other imports could come from the Namibian offshore Kudu gas field. Proven reserves are 1.4TCF and there is large potential expected from these fields. If larger reserves are realised, electricity generation capacity could be sustained in the Northern and Western Cape of South Africa. The market for gas would need to be established for gas supply contracts to be arranged so that the gas price could ensure commercial operation of the plant for its technical lifetime. Gas turbine (GT) plants could be built at Saldanha, Cape Town and near the Coega industrial zone.

Eskom is planning to build two OCGT, one at Mossel Bay with a capacity of 450 MW and using natural gas from LNG and one at Atlantis (Cape West Coast) with a capacity of 600 MW using liquid distillate fuel. Both stations are expected to begin service early in 2007[EIA OCGT 2005]. The DME has asked for tenders from IPP to build two OCGT plants, one in Kwazulu-Natal of between 750 MW- 830 MW and the other in the Eastern Cape of between 300 MW- 360 MW. Electricity from the stations will commence by the beginning of 2009 [Olivier 2006].

This supply plan considers building new open cycle gas turbines (OCGT) of 240MW each (2 units of 120MW) that could be fed with natural gas, LNG or diesel. The plants would supply peak load capacity as the fuel costs could be high and the efficiency is 32% to 35%. The capacity investment costs are the lowest compared with other power stations and they can be built in two years.

Combined cycle gas turbines (CCGT) units of 387MW rated capacity are also included in the plan. CCGT could be run as intermediate or even base load capacity if gas supplies are plenty and of low cost. The thermal efficiency of CCGT is between 50% and 60% as a steam cycle recuperates heat from gas combustion. CCGTs can be started quicker and have better load following characteristic than coal fired stations.

The costs and performance data for GT plants and their related fuels are included in the supply options Table 4.1 for comparison between other generation options.

4.2.4 New pump storage hydroelectricity

South Africa is a dry country with few rivers and dams for large hydroelectric exploitation. Hydropower is robust in being able to be operated immediately to respond to load peaks although large water resources are needed. Pump storage schemes are useful in electricity load management especially for peaky loads as they pump water to fill reservoir when there is surplus generation and provide hydroelectric power when there are shortages. Feasibility studies have been undertaken by Eskom on two possible new sites, Braamhoek in Kwazulu – Natal and Steelpoort in Mpumalanga. Braamhoek has received a record of decision and consists of 4 units of 333MW that could be commissioned by 2012. The cost and performance data for Braamhoek are included later.

4.2.5 New imported hydroelectricity

Africa has a large unexploited hydro power potential from the Congo, Nile and Zambezi rivers. Investments in hydroelectric schemes could supply capacity to the power pools which transmit the electricity to other countries or even Europe. There are plans by Mozambique to build a 1300MW station at Mepanda Uncua on the Zambezi River and export the electricity to South Africa [NIRP 2003].

The Inga Rapids on the Congo River in the Democratic Republic of Congo (DRC) has large potential for run-of-river hydroelectricity generation. There is a plan by Eskom to spend \$50 billion on 40 GW of capacity that could supply Africa with much needed power [Reuters]. Transmission networks could be upgraded and built to export the electricity to Southern and Northern Africa. Construction could start in 10 years after environmental assessment and feasibility studies are conducted.

4.2.6 Renewable energy for centralised electricity generation

4.2.6.1 Wind energy

Wind energy could be installed at some areas of South Africa's coastline where there are sufficient wind speeds and availabilities. Demonstration sites such as Kliphuevel outside Cape Town have been testing the potential for wind generated electricity. Projects are planned such as the Darling wind farm which will act as an independent power producer and sell power to the grid. More demonstration sites are needed around South Africa to quantify the level that wind energy could provide. In Germany and Morocco wind turbines have reached 50% capacity factor due to favourable wind conditions whilst conditions in South Africa are expected to be between 20% and 30%. The investment costs are still high and there is no local experience of integrating a non-dispatchable resource to the electricity generation mix. In California, wind forecasts are sent to the electricity generation controllers every day so that dispatching of power stations can be designed around wind conditions. Wind turbine technology is improving around the world and single units of 4MW have been commercialised. The costs of the new turbines are expected to decrease over time as there is a larger take-up by Europe, America and Asia. Wind turbines have been included in this supply plan for the purpose of screening curve analysis.

4.2.6.2 Solar energy

South Africa has a high level of solar radiation particularly in the Northern Cape. A demonstration solar thermal plant is needed to begin the usage of the resource. The technology could be a heliostat where a central receiver with a thermal engine is surrounded by arrangements of mirrors that track the sun and focus the radiation onto one central point. Alternatively a parabolic trough arrangement of mirrors would heat liquid flowing in pipes

along the focal point of the mirrors. This plan considers a solar thermal plant of 100MW with the capability of storage.

4.2.6.3 Other supply options

Industrial activities like pulp and paper mills and sugar refineries could construct additional electricity generation plants to burn the waste products from industrial processes. There is very limited biomass in South Africa for wide scale electricity generation.

Areas remote from the electricity network could use renewable energy or small diesel generators to provide electricity. The cost to extend the grid could be high and other generation could have lower costs. Options for distributed electricity generation include wind turbines, solar thermal, solar photovoltaic panels, micro-hydro, diesel and petrol generators. The cost of renewable energy equipment is high and if there is widespread usage of the technology the costs could be reduced. This supply plan only considers centralised generation technologies. Inclusion of the possibility of large scale distributed generation is beyond the scope of this IRP as it is currently small in comparison to centralised capacity.

4.3 Power station cost and performance data

Data was collected mostly from the National IRP supply planning to be used to compare the costs of generating options.

Reference	Power station	Unit Capacity (MW)	Life years	No. units	fees. & EIA lead time years	Constr. time years	Avail. (%)	Total Capital Costs (\$/kW)	Fixed O&M costs (\$/kW/year)	Fuel calorific value(GJ/ton or GJ/m ³)	Fuel cost (\$/ton solid or \$/m ³ gas)	Eff (%)	Fuel costs (US c/kWh)	Variable O&M costs (US c/kWh)
(NIRP)	Mothballed Coal PF	1140	15	NA	-	-	86	453	12.3	19.4	6.7	28.0	0.44	0.083
(NIRP)	Coal PF dry	657	30	6	6	4	88	996	12.3	19.4	6.7	35.4	0.35	0.083
(NIRP)	Coal PF dry, fgd	642	30	6	6	4	88	1089	12.6	19.4	6.7	34.6	0.36	0.083
(NIRP)	FBC(discard)	233	30	2	2	4	86	1074	22.7	13.9	2.3	37.4	0.16	0.217
(NIRP)	GT (natural gas)	120	20	2	2	2	90	426	8.9	35.0	140.0	32.3	4.46	0.732
(CPP)	GT (diesel)	270	20	1	2	2	90	430	10.0	42.5	300.0	35.0	7.26	0.200
(NIRP)	CCGT (natural gas)	387	25	5	3	3	92	562	17.4	35.0	140.0	48.0	3.00	0.105
(NIRP)	PBMR (nuclear)	165	40	8	3	4	86	1837	18.7	-	-	40.5	0.50	0.075
(NIRP)	PWR (nuclear)	874	40	2	3	4	79	1777	63.1	-	-	31.5	0.50	-
(NIRP)	Pump Storage	333	40	4	4	7	97	351	9.5	-	-	-	0.62	0.100
(NIRP)	Imported Hydro	300	30	4	-	7	90	1793	207.0	-	-	-	-	-
(NIRP)	Wind	1	20	20	4	2	97	857	25.0	-	-	-	-	0.400
(NIRP)	Solar Thermal	100	30	3	6	3	94	3720	16.0	-	-	-	-	-

Table 4-1 Power station cost and performance data

- The values are in US dollars and are constant monetary value
- An exchange rate of R9/\$ is used.

Operating and maintenance costs of the mothballed stations are the same as for new PF coal stations. Discard coal costs were assumed as there they have not yet been utilised. The higher cost of pipelined natural gas is selected from the Kudu gas study for use in this study as there is uncertainty of supplies. The price of LNG is expected to be higher than natural gas and could be represented by a magnitude increase in the supply curve. Data selected for the PBMR are reflective of initial construction and not further improvements. Capital cost for generic pump storage is usually \$778/kW but a lower value representative of Braamhoek is used. Fuel costs for pump storage are assumed to be 40% higher than the costs of fuel coal added to the variable operations and maintenance costs for a PF stations as these types of stations would supply the electricity to pump the water for later use.

Screening curves are calculated for a range of power stations using the life-cycle levelised costs (Us c/kWh) of each option for the duration of their economic life. A discount rate is used to discount all costs into the future as present value costs are used for the year commissioning begins for all stations. The total costs are the costs of the capital expenditure added to the variable and fixed operations and maintenance costs and fuel costs. Variable costs and fuel costs depend on the amount of utilisation but fixed and capital costs are the same irrespective of the electricity produced. The total capital costs depend on build plans as earlier investments cost more and could significantly change the levelised costs if there is a large capital component. The build plan is shown for all stations [NIRP 2003].

Year	-5	-4	-3	-2	-1
CPF	7.2	1.5	39.0	53.2	6.3
CCGT		2.5	5.0	50.0	45.0
Mothballed CPF		3.0	30.0	40.0	30.0
FBC	4.5	1.5	39.0	53.2	6.3
GT NG		5.0	5.0	20.0	75.0
PBMR	5.0	20.0	35.0	30.0	10.0
Solar Thermal			30.0	30.0	40.0
Wind Turbines				50.0	50.0
Pump Storage		10.0	30.0	30.0	30.0

Table 4-2 Percentage feasibility and construction investment for each year

The year of commissioning is year 0. Percentage yearly expenditure of the total capital to be spent on construction is shown in the above table. The values in italic text are the costs for the feasibility and EIA, represented as a percentage of the total capital costs. Feasibility costs for the PBMR are spent 5 years before commissioning and are 5% of the total investment costs whereas other feasibility costs are included separately from construction costs.

The screening curves of the life-cycle levelised costs (US c/kWh) are calculated over a range of load factors. The total costs are divided by the amount of electricity for each 10% increase in electricity production. Base load (figure 4-1) and peaking supply options (figure 4-2) are shown on separate plots. Imported hydro and PWR were not included in the screening curves.

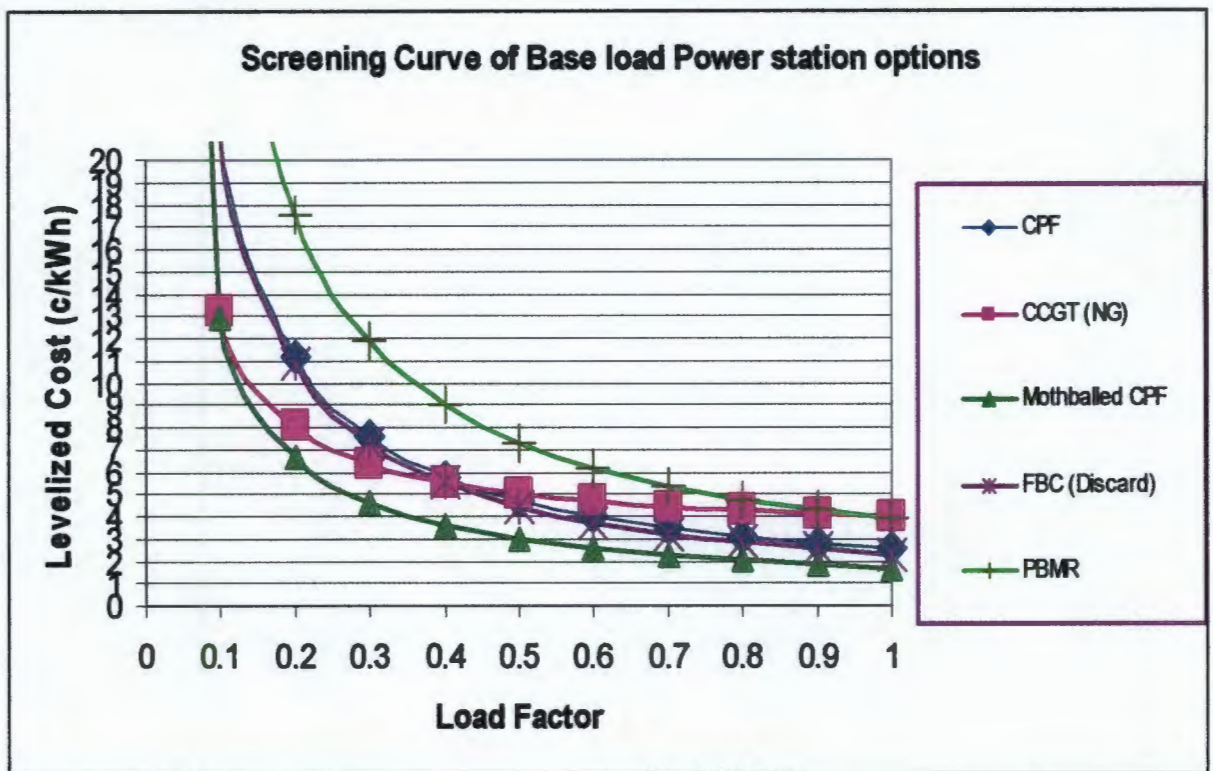


Figure 4-1 Screening curves of levelised costs for Base load supply options

Mothballed PF power stations are the overall least-cost options but are limited to the available reserve storage. The least-cost base load new supply option is FBC which is only slightly lower than the cost of new coal fired PF stations with FGD and dry cooling. The costs of the PBMR are high and only competitive with CCGT at full load factors. Lower costs could be achieved for the PBMR with technology development.

The price of natural gas or LNG is not assured so the cost of \$4/GJ is used. CCGT levelised costs are less than coal technologies for load factors below 0.4. A lower gas price would decrease the levelised costs for CCGTs further. A gas price of \$2/GJ would make CCGT competitive with coal technologies at base loads.

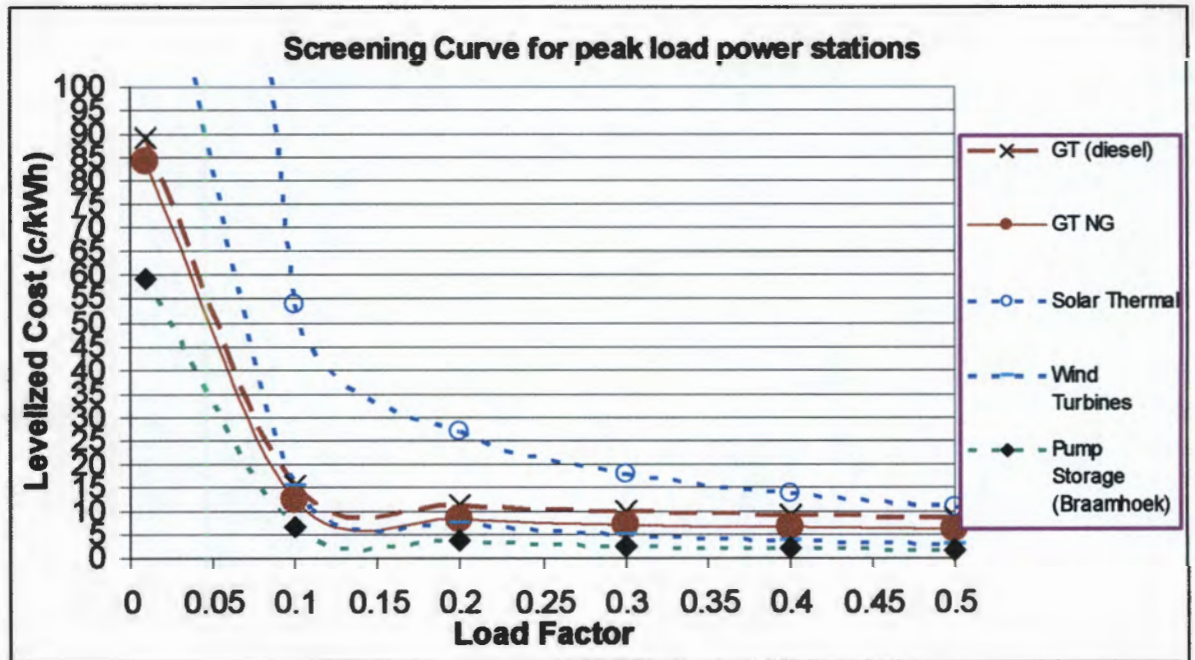


Figure 4-2. Screening curves of levelised costs for Peak load supply options

Even though the pilot shows that the least cost option for peaking load factors is the Braamhoek pump storage option, it has limited capacity and is reliant on electricity produced at low peak times to pump water into the higher reservoir for later use. The additional capacity of pump storage supply options is very limited as suitable sites are few and there may be added costs for pumping during supply shortages. Investments costs for other pump storage schemes would be higher and the levelised costs would be higher. OCGT stations are more suitable to meet unexpected peak demands as they are can be operated whenever needed. OCGT plants have generally lower capital investment costs than typical pumped storage plants and will be preferred for very low load factor. GT have lower life-cycle levelised costs than CCGT for utilisation less than 10% as their investment costs are lower. Above 20% utilisation CCGT become cheaper than GT as their higher efficiency results in lower fuel cost and therefore lower overall life-cycle levelised costs.

Wind power is entirely non dispatchable and the load factor would be dependent on wind conditions. A maximum total utilisation factor of 0.5 was chosen to represent the limits that wind turbines could be used throughout their lifetime. Wind turbines levelised cost drop significantly between 15% and 40% utilisation but cannot be adequately compared as there production is difficult to predict. Solar thermal technologies are the most expensive overall option. Solar thermal plants could have storage and are also dispatchable during the night. A maximum utilisation factor of 0.8 was used for solar thermal technologies.

4.4 Likely capacity investments

It is estimated that investments of R107 billion will be required for electricity service delivery between 2005 and 2009 and Eskom will spend R84 billion of this and independent power producers (IPP) will spend the remaining R23 billion [Stanford 2005]. Eskom is committed to the demothballing process of 3 stations and plans to spend R4 billion on each station between 2005 and 2011 or 2012. A total 3500MW would be added to the supply. The shortage of peak load supply has prompted the DME to invite tenders for 1000MW of peaking power plants to be fully operational by the end of 2008 [Furness 2004]. An OCGT would be the candidate of choice due to the short construction period. Investments in base load capacities could include FBC, PF coal power stations or CCGT to be operational from 2010 [NIRP 2003]. The timing of investments depends on the scale of DSM activities within the next years. An integrated resource plan incorporates the changes to the supply expansion plan due to different levels of DSM and EE activities.

5 IRP Modelling

An energy model is needed that can optimise energy supply options based on the costs and supply constraints. The final demand for energy can be met with supplies under a set of user defined constraints. Many energy models do not allow sufficient representation of patterns of demand use as the demand pattern is entered as a load duration curve or with very few time-slices. The modelling of this IRP requires detailed load profiles so that the dynamics of electricity supply and demand is captured. TIMES (The Integrated MARKAL-EFOM System) is an extension to the MARKAL family of models developed by the Energy Technology System Analysis Programme (ETSAP) of the International Energy Agency. MARKAL is an acronym for market allocation and EFOM an acronym for Energy Flow Optimisation Model. TIMES is a combination of the two models and uses linear optimisation to find the least cost target referred to as the objective function [Solomon 2003].

TIMES was chosen as it can represent load profiles with sufficient detail so that the seasonal, daily and hourly demands can be modelled. TIMES is a bottom-up model with final demand driving a vertical energy chain of resource extraction, electricity generation, transmission and distribution. The supply plan with the least cost on the system is identified by optimisation of all available resources to meet the demand hence the total system costs are minimised in all TIMES optimisations.

An energy models try to satisfy the fundamental equation:

$$\text{Production} + \text{Imports} - \text{Exports} - \text{Consumption} \geq 0$$

TIMES has partial equilibrium constraints of capacity transfer such that:

Capacity in the current period = Remaining residual capacity + New investments already made in previous periods which are still available.

5.1 Model structure

The IRP structure is made up of the demand sectors that are linked to supply generation via transmission and distribution. Each sector consists of various loads that have fixed usage patterns in which the final demand for that specific load can be met. Each sector is supplied by distribution equipment that is modelled as an energy process with losses. The group of distribution loads are fed with electricity from transmission lines that are also modelled as an energy process with losses. Power stations produce electricity to be transmitted. Fuel for power stations is produced from energy processes such as mining, nuclear fuel fabrication and refineries. There is an activity cost to produce each fuel commodity besides hydro resources.

A reserve margin is observed so that sufficient generation capacity is available in the event of some capacity loss. TIMES does not handle reserve margins fully as a reserve margin is a function of load, loss-of-load-probability (LOLP), station availability and unserved energy but TIMES does not consider LOLP and unserved energy. The stipulated reserve margin forces the plan to build capacity that may not be used resulting in extra costs. Unfortunately, inaccurate reserve margin representation cannot be avoided as it is one of the limitations within TIMES and MARKAL. Energy models specifically for electricity generation would be needed to observe the affects of a reserve margin.

The model is built to plan for 22 years starting from 2002. TIMES allows flexible time periods to be used so that not every year needs to be calculated. This feature reduces computation time of the model whilst allowing more years to be modelled. There are eleven time periods, each of one year duration, from 2002 to 2012, four time periods, each of 2 years duration, from 2012 to 2020 and a single time period of fours years duration ending in 2024.

5.1.1 Time-slices

An IRP considers demand side programs that aim to change the demand at peak times. An adequate number of time slices are needed to model demand side initiatives as each initiative aims to change the load usage at specific times. The cost to produce electricity varies over time with base load power stations supplying lower cost electricity than peak load. Base

loads stations are dispatched for the majority of the time, intermediate stations typically less than 50% of the time and peaking station for only a few periods a year. Representation of the demand by many timeslices is therefore necessary for realistic power station dispatching which has a direct impact on the benefits of DSM and EE programs.

Every modelled year is divided into three seasons. Seasonal segmentation of the year is calculated from the total yearly load profile. Each months of the year is grouped with other months of similar monthly peak loads.

- Summer season occur for 21 weeks of the year
- Winter season occur for 8 weeks of the year
- Intermediate season occur for 23 weeks of the year

The model is limited as the same time-slices are used for all loads. In reality, some industrial loads have very little seasonal variation and could be modelled with one season whilst residential load are highly weather sensitive and could be modelled in more than three seasons. Three seasons were also chosen as a balance between load profile representation accuracy and computation time. TIMES is able to model using any number of time slices but the models become very large when every hour is modelled. The IRP model divided each season into a weekday and weekend each with 24 time-slices. Weighting of each time-slice corresponds to the amount of time that each time-slice exists in the year. A diagram of the 144 time-slices and their annual association is shown in the figure below.

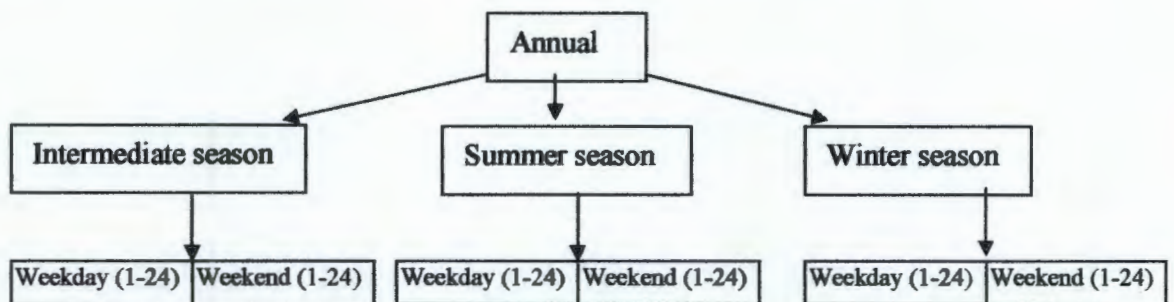


Figure 5-1 Time-slices for IRP model

5.1.2 Electrical demand and loads

TIMES is a demand driven model so every load type for all sectors is assigned with electricity consumption (GWh). As shown in the demand study, there are 16 sub-sectors chosen to represent all sectors in South Africa. There are 100 end-use electrical loads for all the sub-sectors. Each load has a specific yearly load profile as was calculated in the electricity end-use model in the demand study. The yearly load profile contains 8760 values as each hour of the year is represented. There are 144 time-slices used in the TIMES model and the yearly load profile is adjusted to fit the time-slices by grouping the months into 3 seasons as shown in the table below.

Months	Season category
January	Summer
February	Summer
March	Summer
April	intermediate
May	intermediate
June	intermediate
July	Winter
August	Winter
September	Intermediate
October	Intermediate
November	Summer
December	Summer

Table 5-1 Seasonal categories for the year used in the TIMES model

Each load is modelled as a process with a fixed availability as calculated from the load profile. Demand is met by operating the load according to the availability for each time-slice. Summer and intermediate times-slices contain most of the demand as they also contain a higher yearly fraction. Winter peaks are maintained as the winter time-slices have a lower yearly fraction with which to meet the demand. The shape of the load profile is not changed for future years in the reference case as changes will be incorporated into DSM and EE scenarios later. Electricity consumption for every load is projected based on the growths calculated in the demand study.

Electric loads are modelled for each sub-sector and a reference energy system (RES) is built with each load linking together within their respective sector. Demands for electricity are met by specific loads. Loads are grouped by each sub-sector and each sub-sector is grouped into sectors. For example residential sub-sectors: Urban, Electrification and Townships are collected into a residential sector. A diagram showing the levels in the RES is shown below.

The model is demand driven, as mentioned previously, so arrows depict demand flow not supply flow.

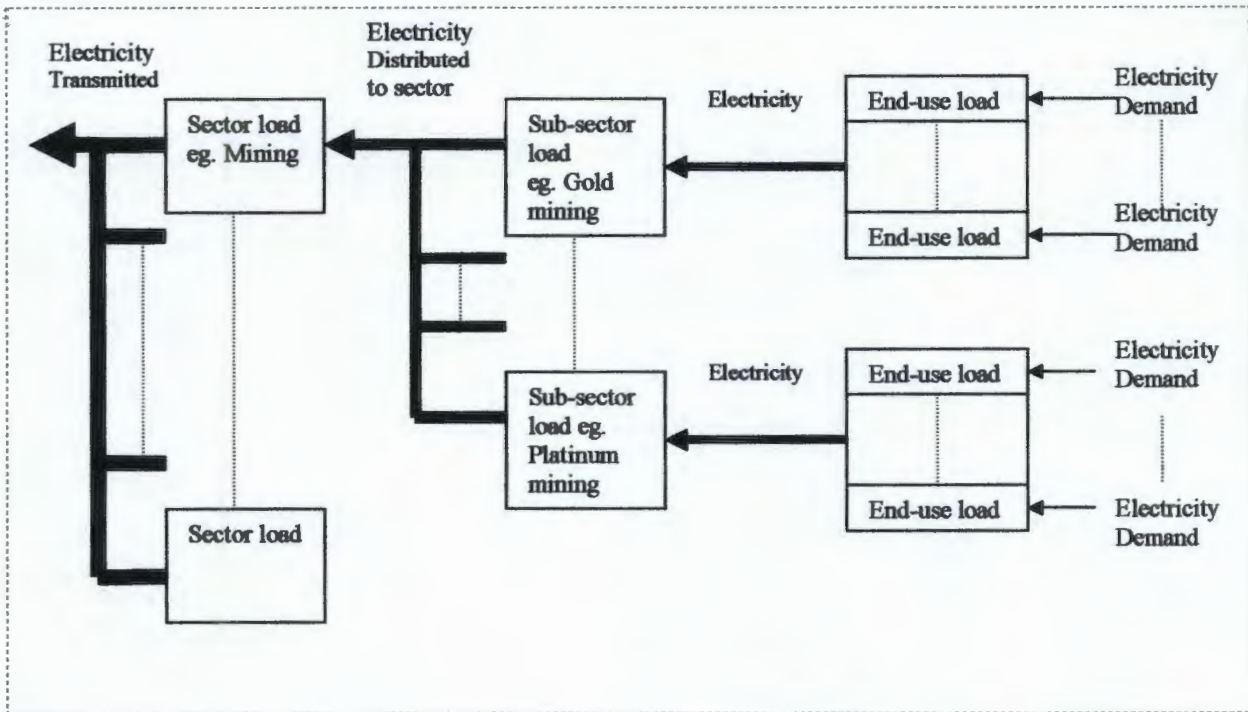


Figure 5-2 Reference energy system of demand with sectors and sub-sectors

Distribution and transmission of electricity is modelled as processes with losses. Distribution losses are assumed to be a constant percentage of transmitted electricity but in reality, higher losses would be attributed to a sector that requires larger reticulation areas in relation to the electrical load sizes such as the residential sector. The percentage energy loss from the NER is used [NER ESS] and the 2002 values are assumed for all modelled years.

- Distribution losses are 5.6% of transmitted electricity
- Transmission losses are 3.79% of produced electricity

The figure below shows the average daily electricity transmitted load profile of weekdays and weekend days for 3 seasons. Losses in transmission are included in the figure and more electricity is produced by the power stations to compensate for these losses¹⁹.

¹⁹ We assume that the power factor is 1. Further capacity may be demanded with poor power factors and power factor correction equipment will be needed.

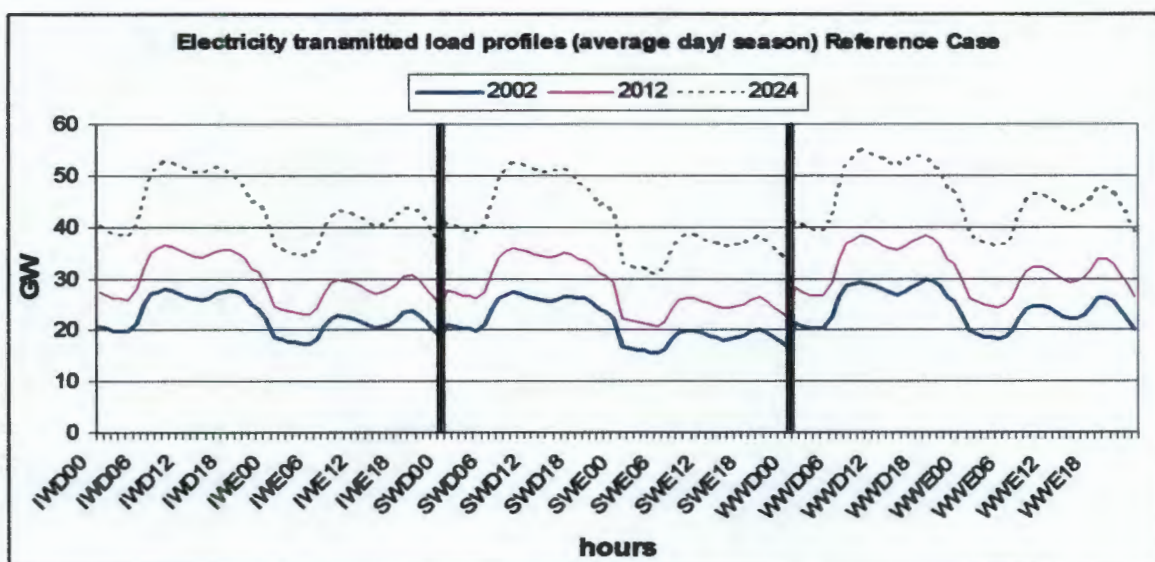


Figure 5-3 Load profiles for average days for selected years

The load factor is will increase to 0.78 by 2012 and 0.79 by 2024 as large industrial growth is expected. Larger commercial and industrial growth than residential growth causes the morning peak to exceed the evening peak after 2012. The reference case assumes that the end-use load profile shape will remain constant and only the magnitude of each end-use load capacity will change in the future. This type of scenario is called “frozen efficiency” as the energy service is met with the same level of energy input.

5.1.3 Electricity generation

The transmitted electricity load profile is supplied by all generating stations. Fuel resources provide the energy input to electricity generation. Costs are included in fuel production. Each station will use the appropriate fuel resource and produce electricity according to its station efficiency in table 4-1. Existing power stations in operation have no capacity investment costs as they have been incurred in the past. Demothballing of stations requires refurbishment and there are capacity costs. New power stations require capacity investment and their cost have been tabulated previously. All power stations have operating and maintenance costs which may be fixed according to the capacity or variable according to the electricity produced or have both components. Both existing and new options compete with each other in supplying the lowest cost electricity at each time-slice that is demanded by the transmission network. The diagram below shows the reference energy system used to model the supply.

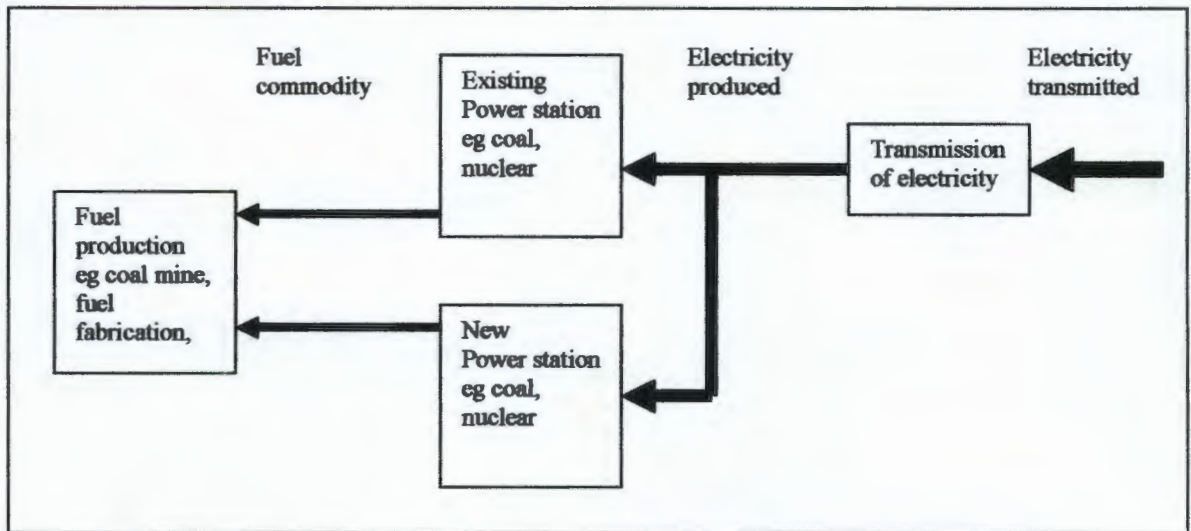


Figure 5-4 Reference energy system for supply side model

Power stations are divided into fuel technology categories. Existing capacity are disaggregated further by Eskom and Municipalities/Private generation. Construction times for new investments (Table 4-1) are included in the supply expansion options as shown in the table below. Capacity addition limits for new and previously untested technologies are gradual.

Capacity Limit (GW)	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2014	2016	2018	2020	2024
Demothballed Camden	0.00	0.00	0.00	0.38	0.76	1.14	1.52	1.52	1.52	1.52	1.52	1.52	1.52	1.52	1.52	1.52
Demothballed Grootvlei	0.00	0.00	0.00	0.00	0.00	0.38	0.75	1.13	1.13	1.13	1.13	1.13	1.13	1.13	1.13	1.13
Demothballed Komati	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.30	0.61	0.91	0.91	0.91	0.91	0.91	0.91	0.91
Existing Imported electricity	0.91	0.91	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28
Existing Eskom Coal stations	30.17	30.17	30.17	30.17	30.17	30.17	30.17	30.17	30.17	30.17	30.17	30.17	30.17	30.17	30.17	30.17
Existing Eskom Coal stations Decommissioned	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	0.00	0.00
Existing Municipal & Private Coal stations	2.07	2.07	2.07	2.07	2.07	2.07	2.07	2.07	2.07	1.44	1.44	1.44	1.44	1.44	0.72	0.72
Existing Eskom Gas Turbines	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34
Existing Municipal & Private Gas Turbines	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
Existing Eskom Hydroelectric Stations	0.58	0.58	0.57	0.57	0.56	0.56	0.56	0.55	0.55	0.55	0.55	0.51	0.51	0.51	0.51	0.51
Existing Municipal & Private Hydroelectric Stations	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Existing Eskom Nuclear Koeberg	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80
Existing Pump Storage Stations	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.40	1.40
New Combined Cycle Gas Turbines	0.00	0.00	0.00	0.00	0.00	0.00	0.38	1.16	1.93	1.93	1.93	1.93	1.93	1.93	3.00	3.00
New Coal Pulverised Fuel (cct)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.92	3.60	3.60	5.50	7.20	7.20
New Fluidised-Bed Combustion Stations	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.50	1.00	1.50	2.80	2.80	2.80
New Imported electricity	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	1.00	2.00	2.00	2.00	2.50	2.50	2.50
New Open Cycle Gas Turbines	0.00	0.00	0.00	0.00	0.00	0.00	0.24	0.72	1.20	1.68	2.16	2.40	2.40	3.00	3.00	3.00
New Open Cycle Gas Turbines (Liquid fuel)	0.00	0.00	0.00	0.00	0.00	0.50	1.00	1.00	1.00	1.00	1.50	1.50	2.00	2.00	2.00	2.00
New Pebble-bed Modular Reactor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.17	0.17	0.35	0.70	1.50	3.00	3.00	3.00
New Pump Storage Stations	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.67	1.33	1.33	1.33	2.00	2.00

Table 5-2 Fixed Capacity Addition Limits for Supply Options

Some capacity will be decommissioned in the modelled years. Coal stations of 1.9GW operated by Eskom will be decommissioned by 2020 and 1.35 GW of municipality and private coal based capacity will be decommissioned by the same year. A relatively small amount of Eskom's hydro-electricity will also be decommissioned as is shown in the above table.

Capacity is added as it is needed in the model but in reality stations can only be added in discrete capacities. Investment could be incurred later than the years chosen by the model but the minimum reserve margin would then be violated. Early investments cost more but offer higher system stability with an increased reserve margin and excess capacity until all the capacity is fully utilised. A reserve margin of 15% is required as some stations may be unavailable for more time or for more capacity than the expected availability. As mentioned previously, the real peak demand will be higher and although only for a very short period extra capacity is needed for just that extra demand. Interruptible supply agreements can reduce the need for such peaks and an available capacity of 1510 MW is attainable from 2002 to 2007 [NIRP 2003]²⁰. The real peak is higher than the average peak used in the load profile study. As the TIMES model calculates the reserve margin from the average peak a higher reserve margin of 20% is chosen because extra supply capacity is needed even when all interruptible loads are switched off. A supply expansion plan is shown in the figure below.

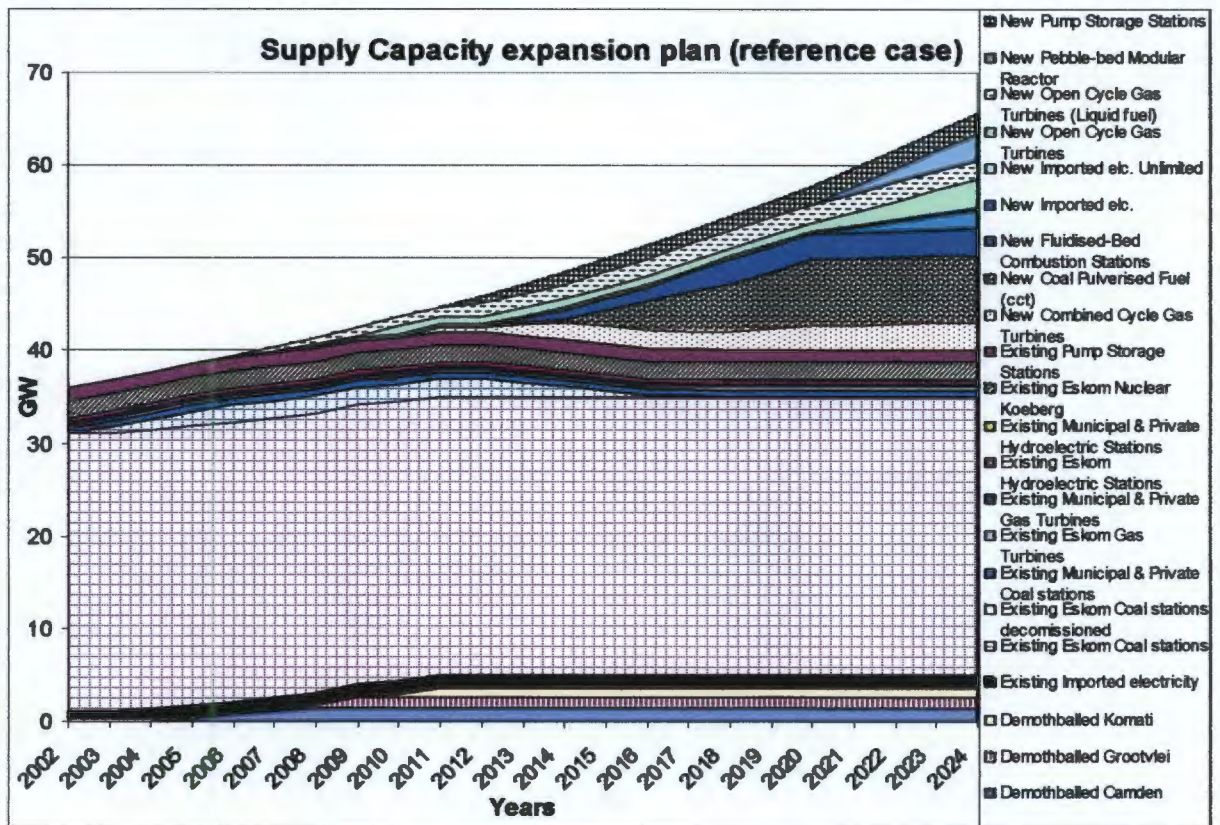


Figure 5-5 Supply Capacity expansion plan for the reference case.

²⁰ National Integrated Resource Plan 2003/2004 appendix 2

The full operating capacity is available for use by 2006 to meet the reserve margin but capacities are not fully utilised. Demothballed stations begin to be recommissioned by 2005 and are totally available by 2011 with 3.56 GW of extra capacity. The three demothballed stations provide intermediate load as they are operated between the hours 7:00 to 23:00 on weekdays and on some weekends. Peak load capacity is needed by 2006 although just to maintain the reserve margin such as new imported unlimited electricity which never produces electricity. Open cycle gas turbines provide peak loads from 2009 and 1.16 GW would be needed by that year even though the capacity is under utilised as the operating costs are higher than other stations. The model invests in 0.5 GW of combined cycle gas turbines by 2011 to be used for intermediate loads. CCGT capacity increases to 1.93 GW by 2014. New pump storage capacity is commissioned in 2012 and provides network stability by maintaining the reserve margin. A total of 1.3 GW of pump storage capacity is available for use by 2014. Base load capacity is needed by 2014 and both coal pulverised fuel (CPF) and fluidised-bed (FBC) stations are commissioned. By 2016, 3.2 GW of CPF is built and 1.5 GW of FBC. New imported electricity is introduced from 2020 in addition to new PBMR stations.

5.1.4 Demand based resources

Once the reference case has been established it is possible to add scenarios such as a DSM scenario which sets out to achieve similar targets to those used in the NIRP. There are load reductions from energy efficiency and load management for specific loads as was mentioned with the end-use load profile study.

EE measures are modelled by allowing the efficiency of devices to increase by a limited amount each year but the same load profile shape is maintained. Load management such as ripple control or time-of-use tariffs change the shape of the profile as electricity use is shifted from times of system peaks to other times. The NIRP allocates 49 MW of peak demand reduction from water heater ripple control annually and 40.9 MW from industrial and mining load management annually. Ripple control is modelled using the ripple control load profile and industrial and mining load management is modelled as a tariff affect where usage during peak times (weekdays 7:00-10:00, 18:00-21:00) is shifted by the same amount to following hours. In other words, a 20 MW reduction during the 7:00 time period will be shifted to a 20

MW increase at 11:00. Only two load profiles were changed; namely motive power use in gold mining and heating for non-ferrous metals as they are the largest loads within mining and industry respectively. The reduction target was equally divided between the two loads and in reality many other loads would also be used on a time-of-use tariff.

It is easier to model EE measures than load management as the complete profile is reduced not only for specific times. The NIRP states that 300GWh could be reduced every year from 2003-2011. The corresponding load reduction of 62 MW per year was also very similar from EE measures. Load management, however, is dependent on the timing of peaks and its operation could vary year by year depending on peak times and tariff rate structures. It is assumed that all load management is identical each year in the model. Ripple control is also operated on weekends but time-of-use load management has no affect on weekends as there is no cost incentive for off-peak times. The system load profile of the DSM scenario for each daily load profile is compared with the reference system profile in the figure below.

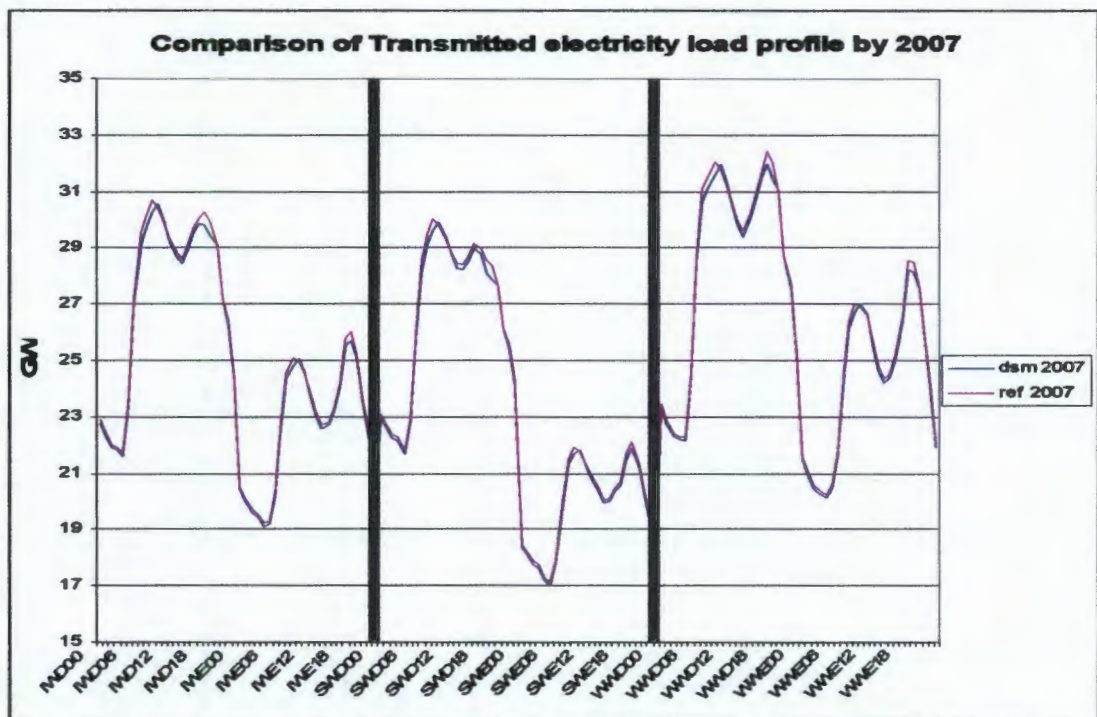


Figure 5-6 System load profiles for reference and DSM scenario 2007

A reduction of 527 MW is observed during winter weekdays at 19:00 by 2007. The load management profile for ripple control needs to be adjusted as a new peak occurs from 2008.

Practically, the new peak would be avoided by changing the operation of the ripple control such that water heaters are turned on more gradually.

There are significant changes to the system expansion plan in the DSM scenario. The existing capacity is made fully available by 2007 not 2006. Demothballed Grootvlei is required by 2009 not by 2007 and Komati's operation is delayed one year to 2011. Less reserve peak capacity is needed and new OCGT capacity is needed for peak demand only in 2010.

5.1.5 Medium impact DSM scenario with costs

Each DSM measure has an associated costs and savings according to what the measure entails. Information and awareness programs have low costs but their success is not guaranteed as it is dependent on people's response and ability to change their energy use. Measures such as efficient technology replacement reduce electricity use immediately but are expensive and require some time to recover initial costs from later savings. As electricity prices increase, there will be more of an incentive to purchase efficient technology as the payback is shorter. It is difficult to determine the amount of efficient technology that will be purchased as it is dependent on market and technology forces.

In this scenario the load management measures from the previous scenario are modelled but additional energy efficiency measures are included. The purpose of this scenario is to determine the sensitivity of energy efficiency measures with their associated costs within the supply plan. There are measures from the commercial, residential and industrial sectors. All efficiency measures are available from 2005 and load management available from 2003. Yearly capacity savings for the commercial and residential sectors are derived from the NIRP and are included with costs in the table 5-3.

DSM measure	Cost (Us\$/kW)	Capacity saved/ year (MW)
Commercial efficient lighting	300	10
Commercial efficient motors	300	3.6
Residential efficient lighting	50	26
Residential efficient cooking	0	1.3
Residential efficient hot water use	0	5.8

Table 5-3 Commercial and residential efficiency measures

Commercial lighting is more expensive to implement than residential lighting as the measure entails changing the fitting and ballast, as with industrial lighting, whereas residential lighting is merely changing from incandescent bulbs to CFLs. The measure to improve commercial motor energy use is a combination of replacement of old motors to VSD and efficient motors as well as better use through supervision. The cost is therefore a combination of these measures and has been derived from industrial efficiency measures. Residential cooking and hot water use have minimum cost as they are mostly behavioural changes. All the residential efficiency measures are assumed to come from urban residential homes.

Industrial efficiency measures are calculated from expected payback periods enumerated for a range of options [Howells et al 2005]. The average price of electricity to industrial customers²¹ is 13.94 c/kWh [NER 2002].

Industrial measure	Potential savings (GWh)	Payback years	Load factor	Total Saved Capacity (GW)	cost Rmillion/GW	cost \$million/GW
VSD	2585	3.60	0.70	0.422	3076	342
Efficient motors	2703	7.00	0.70	0.441	5982	665
Comp Air	3761	0.90	0.86	0.499	945	105
Efficient lighting	2233	3.60	0.65	0.392	2857	317
HVAC	705	2.20	0.60	0.134	1611	179
Thermal	1645	0.80	0.90	0.209	879	98

Table 5-4 Industrial efficiency measures with savings and costs

In the model there were no practical limitations placed on implementation, besides costs and maximum savings, and all the saving where available in 2005. With the above costs, most

²¹ Industrial customers include manufacturing, mining and agriculture and the price of electricity varies for each type. An average price was determined by weighting the price contributions from each customer type based on the amount of electricity they consume.

measures were implemented in 2005. Efficiency in commercial motor use and industrial lighting was delayed until 2006 and replacement to efficient motors by industry was delayed until 2007 as it was the most expensive measure. Due to the immediate implementation of efficiency measures the total load profile was reduced by 2.2 GW at peak times in 2010, as is shown in figure 5-7.

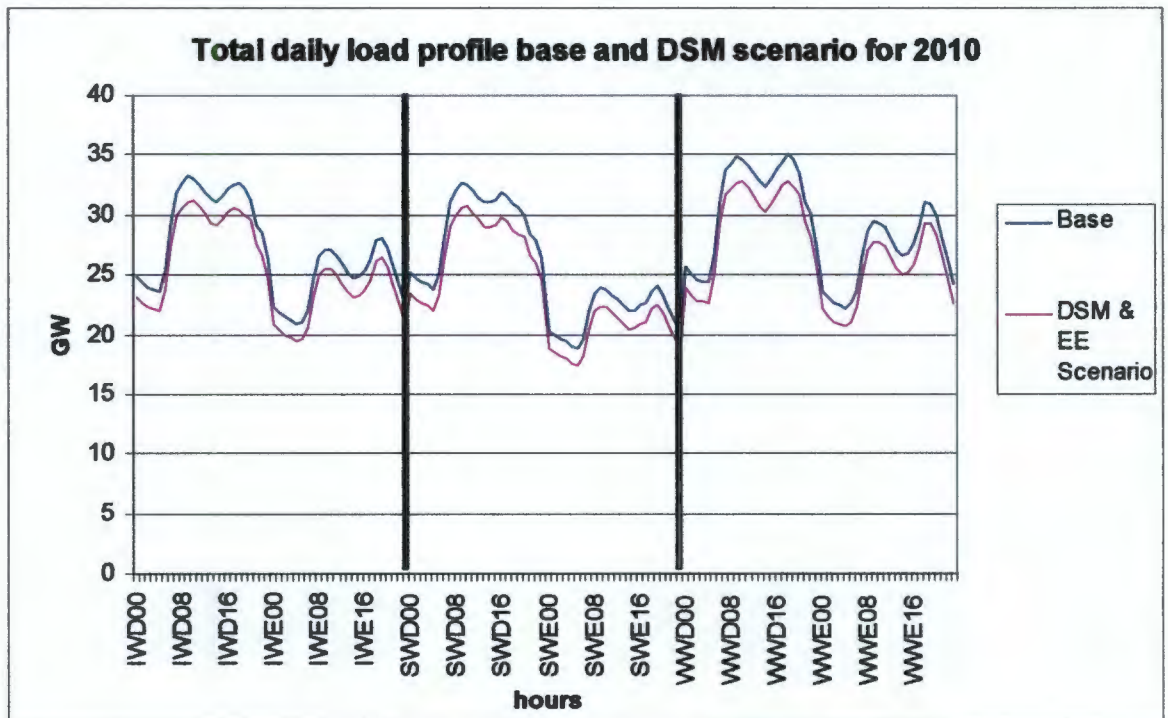


Figure 5-7 Average daily load profiles in 2010 for base case and DSM EE scenario

By 2005, 1.28 GW of peak demand is reduced and by 2007 most the major saving measures are implemented resulting in 2.19 GW peak demand reduction. Commercial and residential measures are increased yearly whereas industrial measures are constant after 2007 and in 2010 the most savings are achieved compared to the reference case. This scenario considers an accelerated implementation of EE measures in the industrial sector as no limits, besides maximum savings, are placed on the timing of implementation after 2005.

The supply capacity requirements for the DSM scenario reflect the savings in capacity. In 2005, 1 GW of capacity is avoided and by 2010 the avoided capacity reaches 2.75 GW.

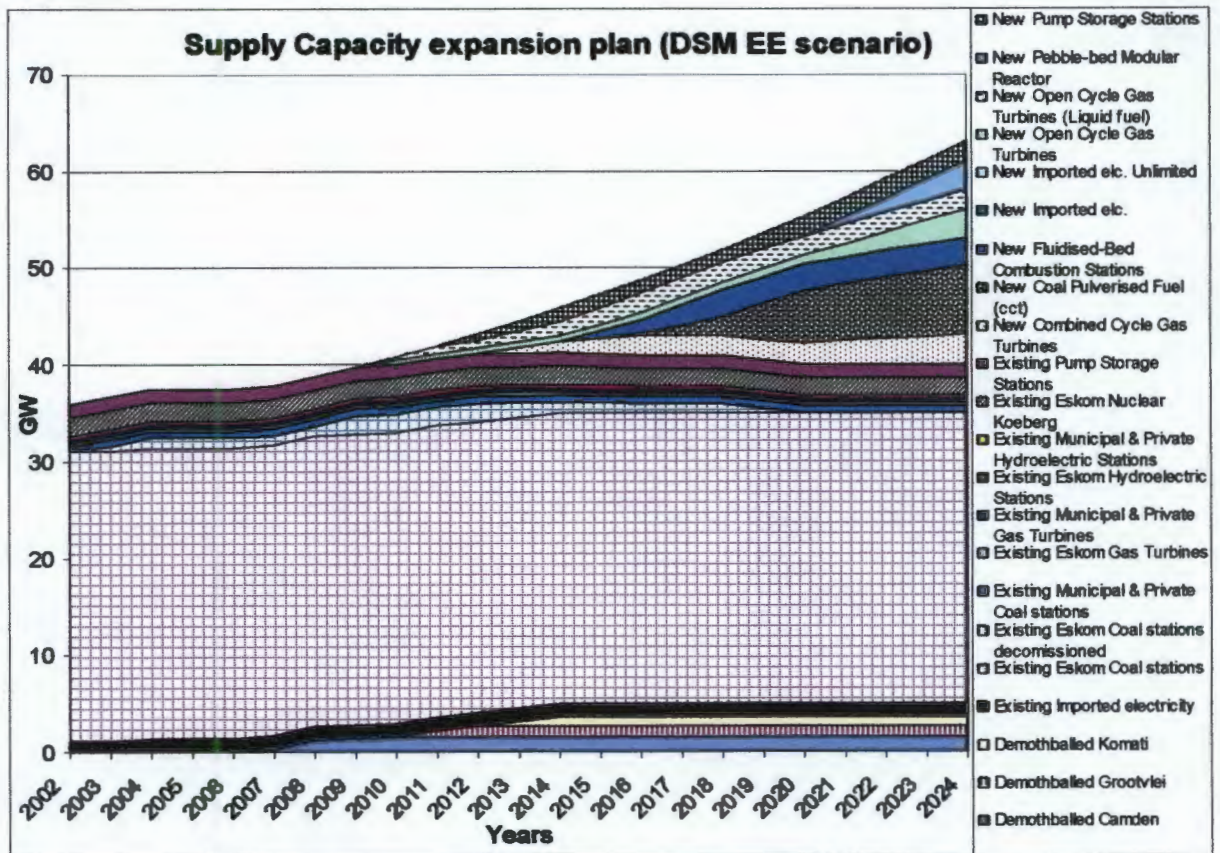


Figure 5-8 Generation capacity and expansion plan for DSM EE scenario

Camden station begins supplying in 2005 and reaches full capacity by 2008 in the base case but in the scenario operations can be deferred by two years. Grootvlei and Komati are deferred 3 years in the scenario as compared with the base case. Existing coal-fired power stations reach full capacity in 2006 in the base case but only by 2009 in the scenario. 530 MW of new CCGT capacity is needed by 2011 in the base case which is delayed by two years in the scenario. A new coal-fired station of 3.2 GW is required by 2016 in the base case but in the scenario only 1.9 GW is needed by 2018. 1 GW of FBC capacity is delayed in the scenario. The base case required imported hydro-power by 2024 to supply electricity and 270MW in earlier years to maintain reserves. The scenario does not require any new imported hydro-power. New OCGT needed by the base case in 2008 are delayed two years and OCGT using LNG needed by 2007 are delayed three years. Both PBMR and pump storage capacity are needed at the same respective time periods in both cases.

In reality, not all the industrial efficiency measures could be achieved in such a short time period and would be spread over a few years. The accelerated implementations indicates that

is it cost effective to implement as many of the measure as soon as possible as new capacity is required in the near term. Peaking capacity will be required by 2007 if there is no major implementation of efficiency measures. Load profiles of the various end-uses have indicated how efficiency improvements of certain loads can reduce peak demand or constant base demand. Further DSM measures such as tariffs would aim at reducing peak demand by shifting loads to non-peak times and reduce the need for expensive peaking power stations.

5.1.6 Renewable energy scenario

Even though there are many applications for renewable energy such as solar photovoltaic for remote areas or bio-gas for remote communities only large centralised projects are considered in this study. There are two renewable energy capacity options included in this scenario: namely solar thermal systems which have an arrangement of collectors to heat a fluid that provides work in an engine to generate electricity and wind turbines which contain propellers that rotate on a horizontal axis and are situated on top of towers. Cost and performance data is shown in table 4-1. Trials are being undertaken on both of these technologies. Eskom installed three wind turbines at Klipheuvel near Cape Town. The turbines required more maintenance than was expected. The site is not ideal as the turbines achieved less than 20% capacity utilisation. Capacity utilisation is increased to 30% in the model as better site may be found with larger wind resources. Additional wind farm projects at other sites around the coast may be able to justify the utilisation of wind power on a large scale. The costs of both wind and solar technologies are high and their likely power production ability could be supported by further trials such as the solar thermal plant near Upington in the Northern Cape.

In the model, solar thermal capacity is available from 2011 and wind turbine capacity from 2008. The solar thermal plant is too expensive and not utilised in the model's expansion plan. Wind turbines are more cost effective and 500MW of capacity are utilised in the base case by 2024 but not in the DSM scenario as lower cost supply options are preferred. Additional information such as wind profiles would enhance the analysis of their inclusion in a capacity supply plan as the times of electricity production from a wind farm may correlate with system peaks.

5.1.7 Greenhouse gas (GHG) emissions accounting

South Africa is a large emitter of GHGs due to large scale production of electricity from coal. There is recent concern about global warming and climate change and nations are introducing means such as the Kyoto protocol to control GHG emissions. The two gasses included in this supply plan are carbon dioxide (CO₂) and nitrous oxide (N₂O). Even though the emissions of N₂O are small compare with CO₂, the global warming potential (GWP) of N₂O is 310 and of CO₂ is 1 [CAPP 2003].

Coal-fired power stations emit approximately 1000 tons of CO₂ [Eskom 2003] and 0.0124 tons of N₂O for every GWh sent out and gas turbines emit approximately 500²² tons of CO₂ for the same unit of electricity [CAPP 2003]. FBC emit more CO₂ than pulverised fuel boilers as the grade of coal is lower and more coal mass is needed for the same output. Hydro-electric²³ and nuclear power stations do not emit any GHG emissions.

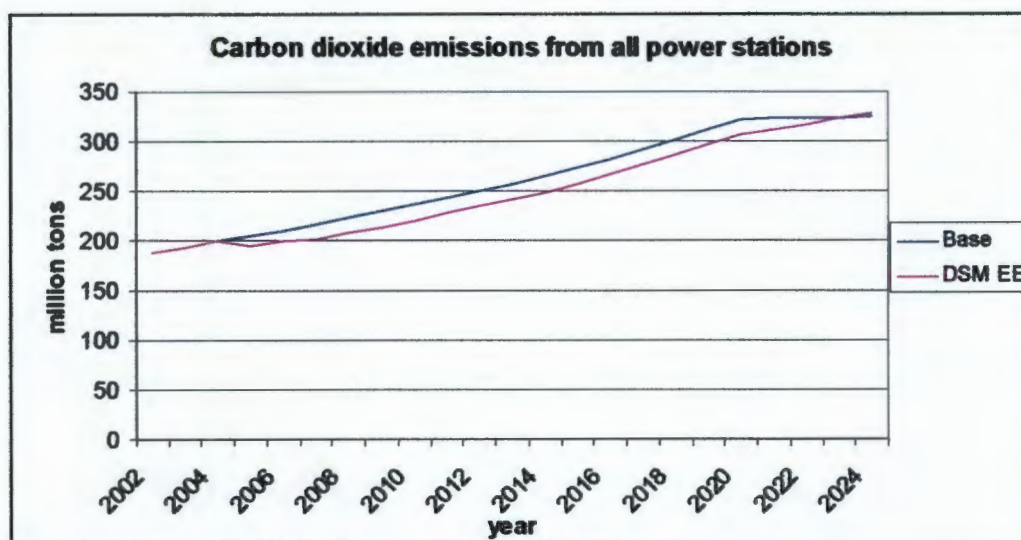


Figure 5-9 Carbon dioxide emissions for base case and DSM EE scenario

In the base case, CO₂ emission increased from 188 million tons in 2002 to 322 million tons in 2020 as coal and gas remain the main source of new electricity production. Emissions are more constant after 2020 as new generation is expected from PBMR technology. The

²² Depending on the type of fuel and if the gas turbine is simple or combined cycle the amount of CO₂ emitted ranges from 0.4-0.59 kg/kWh.

²³ Dams emit methane gas (a GHG of GWP 21) from decomposition of plant matter but these emissions are not included in this study.

medium impact DSM scenario has lower emissions from 2005 to 2023 as less electricity is generated due to the savings. After 2023 lower cost coal power stations are preferred over nuclear options and emissions continue rising.

N₂O emissions were 2340 tons in 2002 and increased to 3938 tons by 2024 in the base case.

5.2 Marginal cost of energy

The marginal cost of energy is the addition of the marginal energy cost (MEC) and marginal capacity cost (MCC). The cost of supplying another unit of energy is the MEC. The marginal energy cost depends on which stations are dispatched to meet the demand at a certain time. The hourly marginal energy cost is the total system energy costs to supply the total system energy for each hour. The marginal energy cost covers all costs that vary with energy use such as fuel and variable operations and maintenance costs. If there is not sufficient capacity to meet the energy demand at a certain time, another unit of capacity is needed and its cost is the marginal capacity cost. Supply capacity investments in generation and transmission are usually lumpy as additions are made in discrete sizes of capacity. Incremental changes in load will not be met directly but with delayed or accelerated investments. Delayed investments will reduce the reserve margin until the capacity is built. Accelerated investments will result in an over capacity for some years before the load increases. The marginal capacity costs will be highest before the new station is built and will be reduced just after the station is built and could even be zero if enough capacity exists.

In the TIMES model, additions in capacity are made in any sizes and not in discrete sizes. Marginal capacity costs will therefore not be truly reflective of reality as capital investments for the construction of power stations are needed before beginning service. The marginal capacity costs are the total system capacity costs for the total system coincident peak demand capacity addition. Marginal capacity costs include all costs that are fixed for the installed capacity such as capital costs and fixed operations and maintenance costs. The marginal capacity cost reflects the cost of new investments in generation and transmission equipment for an expansion plan. The expansion plan indicates what stations are needed to meet the demand at different times. A base-load plant will meet the constant load, peak plants are run only during hours of peak demand whilst intermediate stations operate for many hours of the year but not all (typically between 20% and 80% of the time).

Marginal energy costs (R/kWh) are calculated from the amount of energy produced by each power station for all modelled years. Each station has their associated fuel costs, variable operating and maintenance costs to produce a unit of energy (kWh). Marginal capacity costs (R/kW) consist of the fixed operating and maintenance costs of all stations available for use and the investment cost for new supply capacity. The installed capacities for all existing stations in the base case (reference scenario) are tabulated in table 5-5.

Power station	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2014	2016	2018	2020	2024
<i>Demothballed Camden</i>	0	0	0	0.38	0.76	1.14	1.52	1.52	1.52	1.52	1.52	1.52	1.52	1.52	1.52	1.52
<i>Demothballed Grootvlei</i>	0	0	0	0	0.099	0.211	1.131	1.131	1.131	1.131	1.131	1.131	1.131	1.131	1.131	1.131
<i>Demothballed Komati</i>	0	0	0	0	0	0	0	0.347	0.909	0.909	0.909	0.909	0.909	0.909	0.909	0.909
<i>Existing Imported electricity</i>	0.912	0.912	1.281	1.281	1.281	1.281	1.281	1.281	1.281	1.281	1.281	1.281	1.281	1.281	1.281	1.281
<i>Existing Eskom Coal stations</i>	30.17	30.17	30.17	30.17	30.17	30.17	30.17	30.17	30.17	30.17	30.17	30.17	30.17	30.17	30.17	30.17
<i>Existing Eskom Coal stations decomissioned</i>	0.587	1.088	1.613	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.063	0.144	0	0	0
<i>Existing Municipal & Private Coal stations</i>	0.469	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72
<i>Existing Eskom Gas Turbines</i>	0.342	0.342	0.342	0.342	0.342	0.342	0.342	0.342	0.342	0.342	0.342	0.342	0.342	0.342	0.342	0.342
<i>Existing Municipal & Private Gas Turbines</i>	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
<i>Existing Eskom Hydroelectric Stations</i>	0.506	0.506	0.506	0.506	0.506	0.506	0.506	0.506	0.506	0.506	0.506	0.506	0.506	0.506	0.506	0.506
<i>Existing Municipal & Private Hydroelectric Stations</i>	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
<i>Existing Eskom Nuclear Koeberg</i>	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
<i>Existing Pump Storage Stations</i>	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
<i>New Combined Cycle Gas Turbines</i>	0	0	0	0	0	0	0	0	0	0.531	0.531	1.93	1.93	1.93	2.521	3
<i>New Coal Pulverised Fuel (ccf)</i>	0	0	0	0	0	0	0	0	0	0	0	0.307	3.194	5.061	7.2	7.2
<i>New Fluidised-Bed Combustion Stations</i>	0	0	0	0	0	0	0	0	0	0	0	1	1.5	2.8	2.8	2.8
<i>New Imported etc.</i>	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.165
<i>New Imported etc. Unlimited</i>	0	0	0	0.273	0.273	0.273	0.273	0.273	0.273	0.273	0.273	0.273	0.273	0.273	0.273	0.273
<i>New Open Cycle Gas Turbines</i>	0	0	0	0	0	0	0.24	0.24	0.913	0.913	0.913	0.913	0.913	0.913	0.913	3
<i>New Open Cycle Gas Turbines (Liquid fuel)</i>	0	0	0	0	0	0.50783	0.92	1	1.472	1.5	1.901	2	2	2	2	2
<i>New Pebble-bed Modular Reactor</i>	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
<i>New Pump Storage Stations</i>	0	0	0	0	0	0	0	0	0	0.666	1.332	1.332	1.332	2	2	2
Total	35.91	36.74	37.61	38.52	39.46	40.44	41.45	42.51	43.61	44.74	45.84	48.4	51.27	54.4	57.79	65.52

Table 5-5 Installed capacity (GW) plan for all power stations in the Base case.

The expansion plan for the medium impact DSM and EE scenario is tabulated in table 5-6.

Power station	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2014	2016	2018	2020	2024
<i>Demothballed Camden</i>	0	0	0	0.38	0.76	1.14	1.52	1.52	1.52	1.52	1.52	1.52	1.52	1.52	1.52	1.52
<i>Demothballed Grootvlei</i>	0	0	0	0	0	0	0.779	1.131	1.131	1.131	1.131	1.131	1.131	1.131	1.131	1.131
<i>Demothballed Komati</i>	0	0	0	0	0	0	0	0	0.909	0.909	0.909	0.909	0.909	0.909	0.909	0.909
<i>Existing Imported electricity</i>	0.912	0.912	1.281	1.281	1.281	1.281	1.281	1.281	1.281	1.281	1.281	1.281	1.281	1.281	1.281	1.281
<i>Existing Eskom Coal stations</i>	29.74	30.17	30.17	30.17	30.17	30.17	30.17	30.17	30.17	30.17	30.17	30.17	30.17	30.17	30.17	30.17
<i>Existing Eskom Coal stations decomissioned</i>	0	0.009	0.446	0.921	1.433	1.9	1.9	1.9	1.9	1.91	1.895	1.217	0.234	0	0	0
<i>Existing Municipal & Private Coal stations</i>	0.318	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72
<i>Existing Eskom Gas Turbines</i>	0.342	0.342	0.342	0.342	0.342	0.342	0.342	0.342	0.342	0.342	0.342	0.342	0.342	0.342	0.342	0.342
<i>Existing Municipal & Private Gas Turbines</i>	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
<i>Existing Eskom Hydroelectric Stations</i>	0.506	0.506	0.506	0.506	0.506	0.506	0.506	0.506	0.506	0.506	0.506	0.506	0.506	0.506	0.506	0.506
<i>Existing Municipal & Private Hydroelectric Stations</i>	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
<i>Existing Eskom Nuclear Koeberg</i>	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
<i>Existing Pump Storage Stations</i>	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
<i>New Combined Cycle Gas Turbines</i>	0	0	0	0	0	0	0	0	0	0	0	0.1364	1.93	1.93	2.441	3
<i>New Coal Pulverised Fuel (ccf)</i>	0	0	0	0	0	0	0	0	0	0	0	0	0.1758	4.322	7.2	7.2
<i>New Fluidised-Bed Combustion Stations</i>	0	0	0	0	0	0	0	0	0	0	0	0.905	1.5	2.8	2.8	2.8
<i>New Imported etc.</i>	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.917
<i>New Imported etc. Unlimited</i>	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
<i>New Open Cycle Gas Turbines</i>	0	0	0	0	0	0.042	0.042	0.042	0.042	0.042	0.042	0.042	0.042	0.042	0.042	0.042
<i>New Open Cycle Gas Turbines (Liquid fuel)</i>	0	0	0	0	0	0.042	0.235	0.899	1.471	1.51	1.973	2	2	2	2	2
<i>New Pebble-bed Modular Reactor</i>	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
<i>New Pump Storage Stations</i>	0	0	0	0	0	0	0	0	0	0	0.666	0.861	0.863	0.916	0.992	1.009
Total	35.01	35.76	36.54	37.35	38.21	39.10	40.03	41.00	42.02	43.03	44.17	46.65	49.37	52.33	55.56	63.01

Table 5-6 Installed capacity (GW) plan for all power stations in the DSM and EE scenario.

Marginal costs of energy for every modelled year are calculated for both the base case and DSM EE scenario and shown in figure 5-10.

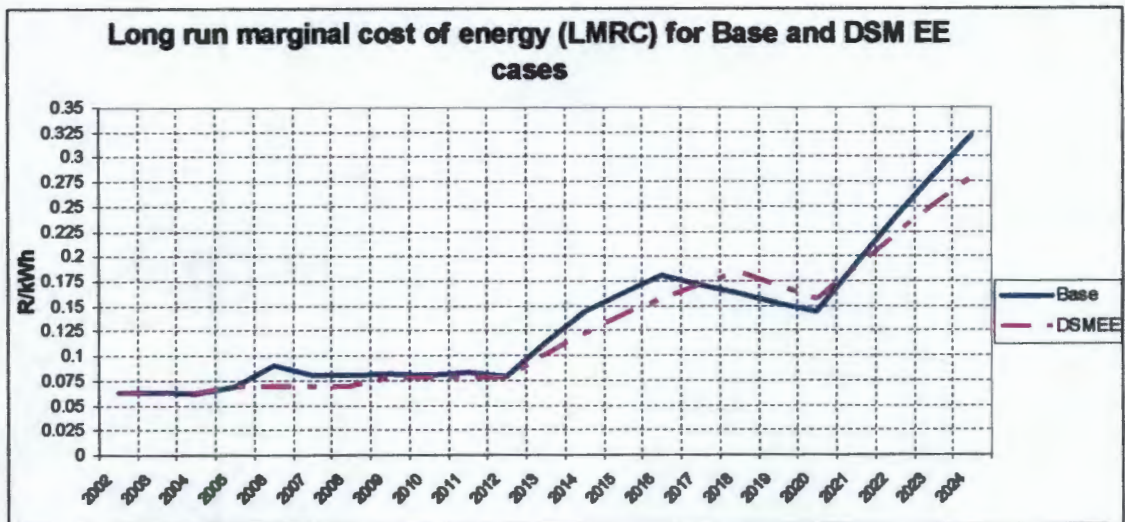


Figure 5-10 Marginal cost of energy for Base and DSM EE cases

Long Run Marginal Cost (LMRC) gradually increases from 0.06 R/kWh in 2002 to 0.08 R/kWh in 2012. The peak in 2006 is reflective of the needed for peaking capacity to meet the reserve margin although the capacity is never used it is still available. Increases in marginal costs from 2012 are when base load capacity such as CCGT and coal PF are built and commissioned. Marginal costs for the DSM EE scenario are slightly lower and increases are delayed as new capacity is deferred.

LRMC calculated here are not complete as the model assumes that all energy needs are served and that there are no interruptible loads available. Unserved energy costs would increase the marginal costs but the usage of interruptible load would decrease the marginal costs as expensive station would be operated less frequently. Loss of Load Probability (LOLP) is also not included in the LRMC calculations. A larger reserve margin would increase the marginal costs as more capacity needs to be available.

In the NIRP 2 [NIRP 2003/2004] the LRMC increased from approximately 0.05R/kWh in 2006 to 0.24 r/kWh in 2014. Thereafter the LMRC stabilises at just below 0.26 R/kWh. The difference to the calculated LRMC in figure 5-10 is because of the non-discrete capacity investment in the TIMES model. Costs are only incurred when a certain capacity is needed. In the NIRP 2 the capital investment is incurred before commissioning and complete stations of discrete sizes are built but only fully utilised a few years later.

6 Findings

Load profiles give many insights into electricity use and how the demand changes according to loads. Electricity planning can be improved using load profiles as individual sector demands are better understood. IRP uses load profiles to determine the potential impact of DSM and EE programs on the system load profile. Each demand based measure can be assessed by its performance within the complete electricity network. Some loads have lower load factors and if used intensively could produce new peak demand times while other loads have very constant utilisation and do not contribute to the difference between peak and non-peak demand. The supply expansion plan is modified with the inclusion of demand resources and can be relied upon as load profiles clarify how demand resources operate.

Major findings include:

- Open cycle gas turbines are needed for peak demand by 2007 in the reference case but only by 2010 in the medium impact DSM scenario. 500 MW of OCGT capacities will need to be built every year after 2007 and over 1 GW of CCGT is needed by 2009 in the base case.
- Refurbishment of mothballed stations and investment in new capacity can be delayed by at least one year if a conservative DSM program is followed or delayed by two to three years if an elaborate EE program is pursued. New FBC and pulverised-fuel coal-fired power stations can be deferred two and four years respectively if extensive EE measures are implemented.
- Residential loads are “peaky” and vary significantly from winter to summer months.
- Industrial loads are very constant and are the largest consumers of electricity.
- Commercial and other manufacturing loads are used mainly during daytime hours.
- Costs of EE measures are not an obstacle to implementation when considering total system costs and most EE programs are implemented immediately or within two years if they are expensive such as motor replacements.
- Load profile analysis of end-use loads enhances integrated resource planning as the characteristics of supply and demand resources can be selected appropriately. ESCos can play a vital role in increasing the demand resources.
- A broad range of loads are supplied by the electricity network and increased measurement and recording of load profiles would assist demand analysis.

- **DSM and EE programs can reduce and defer new supply capacity depending on the scale of the programs. The earlier savings can be implemented the larger impact they will have on future capacity investment.**
- **Residential DSM and EE measures are the most urgent at this stage of electricity use in South Africa as peak capacity could be deferred.**
- **Industrial DSM and EE can have a significant impact on future base load supplies as electricity savings have the potential to be large.**
- **A new peak resulting from water heating control can occur if better control strategies are not sought with which controlled loads can be switched.**
- **The average morning peak will reach the same level of demand as the evening peak by 2010 as there is more growth expected from commercial and manufacturing sectors compared to residential sectors.**
- **Marginal energy costs increased from 0.06 R/kWh in 2002 to 0.325 R/kWh in 2024 in the reference case.**
- **Marginal energy costs for the DSM and EE scenario were slightly lower than for the base case and increases were delayed.**

7 Recommendations

Recommendations for further IRP development include:

- Extend the data base to regions which could assist REDS with IRP and DSM. Each RED should be able to design its own IRP based on the load characteristics within the region and the availability of supplies.
- More EE and load management options such as a residential TOU tariff. Options should be focussed on residential or commercial loads as they contribute mostly to the peaky profile shape. It may be difficult to justify a residential TOU tariff as new metering techniques and equipments are needed but it would be reflective of supply costs.
- DSM and EE of residential loads should be prioritised. Efficient lighting using CFLs, fuel switching to gas for cooking and space heating and solar water heating can reduce residential peaks as these loads have low load factors and contribute to the overall peaks on the system.
- Improve representation of load profiles with data from case studies and energy audits. It is an ongoing task to accurately monitor electricity demand throughout the country and a team should be appointed within the NER or DME to provide valuable information for energy planners and policy makers.
- IRP has the framework to accommodate future possibilities in the energy industry such as distributed generation, large fuel switching, emissions accounting and socio-economic development.
- Additional DSM scenarios can be added as targets are clarified and there is a history of successfully implemented projects.
- The TIMES model does not fully represent all the criteria for maintaining a reserve margin. Energy models more dedicated to electricity planning could be used in conjunction with TIMES to portray more realistic electricity supply conditions.
- Discrete capacity additions and specific capacity build plans could be added to the TIMES model resulting in a more practical plan.

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Appendices

9 Appendix A: Load profiles of sectors supplied by municipalities

9.1 Introduction

An integrated resource plan (IRP) needs detailed information about the electricity demand in the area. If all the sectoral contributions to the system load profile are known, measures to influence the demand patterns can be examined. Accurate disintegration of the total consumption is difficult because of the dispersed use of electricity. Electricity audits done on selected customers from each sector could measure how individual loads are operated over time, such as lights for residential customers and compressors for manufacturing. Due to the lack of time and resources energy audits were not conducted for this report but electricity consumption data from municipal substations was collected. Consumption patterns from substations are the easiest yet accurate starting point for demand analysis in a small region. Demand side management and energy efficiency measures can be considered once there is adequate knowledge about consumer loads and their operation patterns.

9.2 Customer profiles from Municipality data

Municipalities distribute electricity to different types of customers within their locality. The electricity department has measurement logging equipment to record the amount of power sent out by the various substations. A substation will generally have a mix of users groups it serves in one area. There are some areas where a particular sector dominates the sale of electricity such as the residential sector in the suburban areas of a city and the commercial sector in the city centre. It is possible to acquire sector profiles by selecting these areas and removing the components from the other sectors. Accuracy is improved by selecting many substations that distribute large amounts of electricity.

Two weeks of electricity consumption data from all the Cape Town Municipality substations were collected [1]. The logged data is half hour peak power (MW) for a typical summer and a typical winter week. The weeks chosen were:

- 24-30 March 2003 as a typical summer week
- 18-24 August 2003 as a typical winter week

There were no abnormal weather patterns or public holidays during these weeks.

Tshwane municipality have allowed their profiles to be used in this demand study [2].

There are profiles for many sectors including residential, commercial, industrial and agricultural. Yearly variation in demand is also supplied from Tshwane for different sector.

9.3 Cape Town Municipality

Each substation supplied by Cape Town municipality sales data is used to find the customer grouping split in 1999 in a local government publication [3].

Area	Distributor	Name	Voltage	1999 peak MW	1999 peak MVA	1999 power factor	1999 load factor	1999 Agri-MW/culture	Heavy industry	Light industry	Commerce	Transport	Residential income	Low income	Medium income	High income
BB	CT	Milnerion	132/11	29.0	30.2	0.96	0.55	138 919	0%	0%	30%	25%	0%	0.00	0.10	0.36
BB	CT	Montague Gardens	132/11	5.0	5.2	0.96	0.61	26 718	0%	0%	100%	0%	0%	0.00	0.00	0.00
CT	CT	Bonteheuwel	132/11	38.0	39.6	0.96	0.52	171 480	0%	0%	40%	5%	0%	0.10	0.30	0.15
CT	CT	Broad	24412.0	31.0	32.3	0.96	0.52	141 212	0%	0%	20%	35%	0%	0.10	0.25	0.10
CT	CT	City	12359.0	49.0	51.0	0.96	0.58	248 301	0%	0%	5%	75%	0%	0.00	0.00	0.15
CT	CT	Claremont	24412.0	41.0	42.7	0.96	0.60	216 062	0%	15%	5%	40%	0%	0.00	0.05	0.35
CT	CT	Epping	24412.0	34.0	35.4	0.96	0.58	172 928	0%	0%	75%	10%	0%	0.05	0.10	0.00
CT	CT	Eiselen Drive	132/11	24.0	25.0	0.96	0.42	88 008	0%	0%	2%	20%	8%	0.20	0.40	0.10
CT	CT	Eastridge	132/11	32.0	33.3	0.96	0.45	125 216	0%	0%	15%	15%	0%	0.30	0.30	0.10
CT	CT	Greenpoint	12359.0	28.0	29.2	0.96	0.53	129 759	0%	0%	5%	50%	0%	0.00	0.15	0.30
CT	CT	Jan Smuts Drive	132/11	30.0	31.3	0.96	0.47	122 290	0%	0%	20%	15%	0%	0.10	0.35	0.20
CT	CT	Kensington	132/11	33.0	34.4	0.96	0.54	156 178	0%	0%	16%	50%	0%	0.06	0.18	0.10
CT	CT	Koeberg	24412.0	24.0	25.0	0.96	0.55	116 583	0%	0%	20%	67%	0%	0.04	0.04	0.05
CT	CT	Lansdowne	132/11	2.0	2.1	0.96	0.53	9 207	0%	0%	40%	10%	0%	0.05	0.30	0.15
CT	CT	Loch Road	24412.0	51.0	53.1	0.96	0.48	216 560	0%	0%	20%	10%	0%	0.00	0.10	0.60
CT	CT	Mitchell's Plain	132/11	26.0	27.1	0.96	0.45	101 740	0%	0%	10%	20%	0%	0.15	0.45	0.10
CT	CT	Observatory	24412.0	35.0	36.5	0.96	0.52	159 364	0%	0%	0%	66%	0%	0.00	0.04	0.30
CT	CT	Philippi	132/11	42.0	43.8	0.96	0.46	167 802	0%	0%	20%	15%	0%	0.10	0.50	0.05
CT	CT	Roggebaai	12359.0	51.0	53.1	0.96	0.58	259 913	0%	0%	20%	80%	0%	0.00	0.00	0.00
CT	CT	Sea Point	12359.0	25.0	26.0	0.96	0.47	103 795	0%	0%	0%	35%	0%	0.00	0.20	0.45
TB	CT	Bofors	24412.0	36.0	37.5	0.96	0.58	184 399	0%	0%	85%	10%	0%	0.00	0.05	0.00
CT	CT	Spine Road	132/11	25.0	26.0	0.96	0.48	104 895	0%	0%	10%	30%	0%	0.30	0.30	0.00
CT	CT	Tamboerskloof	132/11	40.0	41.7	0.96	0.54	190 724	0%	0%	0%	60%	0%	0.00	0.00	0.40
CT	CT	Vanguard Drive	24412.0	24.0	25.0	0.96	0.46	96 033	0%	0%	25%	10%	0%	0.20	0.40	0.05
CT	CT	Woodstock	132/11	47.0	49.0	0.96	0.58	238 675	0%	0%	20%	40%	0%	0.00	0.10	0.30
CT	CT	Wittevreden	132/11	3.0	3.1	0.96	0.50	13 167	0%	0%	3%	52%	0%	0.30	0.15	0.00
SP	CT	Blaaschop	24412.0	17.0	17.7	0.96	0.52	76 997	0%	0%	10%	30%	0%	0.05	0.05	0.50
SP	CT	Clovetly	24412.0	24.0	25.0	0.96	0.46	96 853	0%	0%	5%	15%	0%	0.05	0.15	0.60
SP	CT	Constantia	24412.0	15.0	15.6	0.96	0.43	57 083	0%	0%	0%	5%	0%	0.00	0.00	0.95
SP	CT	Grassy Park	24412.0	30.0	31.3	0.96	0.45	118 517	0%	0%	15%	15%	0%	0.20	0.35	0.15
SP	CT	Pelican Park	24412.0	22.0	22.9	0.96	0.45	87 305	0%	0%	10%	15%	0%	0.00	0.45	0.30
SP	CT	Piers Road	24412.0	24.0	25.0	0.96	0.48	100 066	0%	0%	5%	20%	0%	0.00	0.05	0.70
SP	CT	Retreat	24412.0	35.0	36.5	0.96	0.50	153 240	0%	0%	20%	20%	0%	0.10	0.30	0.20
SP	CT	Roomead	24412.0	27.0	28.1	0.96	0.52	123 243	0%	0%	5%	40%	0%	0.00	0.10	0.45
SP	CT	Sun Valley	24412.0	18.0	18.8	0.96	0.44	69 325	0%	0%	5%	10%	0%	0.00	0.10	0.75
SP	CT	Steenberg	24412.0	48.0	50.0	0.96	0.54	224 960	0%	0%	20%	30%	0%	0.00	0.10	0.40
TB	CT	Bofors	24412.0	36.0	37.5	0.96	0.58	184 399	0%	0%	85%	10%	0%	0.00	0.05	0.00
BB	CT	Milnerion	132/11	29.0	30.2	0.96	0.55	138 919	0%	0%	30%	25%	0%	0.00	0.10	0.36
BB	CT	Montague Gardens	132/11	5.0	5.2	0.96	0.61	26 718	0%	0%	100%	0%	0%	0.00	0.00	0.00

Table 9-1 Data for Cape Town municipality substations

The main categories of customers are residential, commercial and light industrial without much electricity used for transport and the only heavy industries coming from the SAB brewery in Claremont. There are no substations operated by Cape Town municipality that provide electricity for agriculture. The graph below shows the proportion of electricity sold to different consumer types.

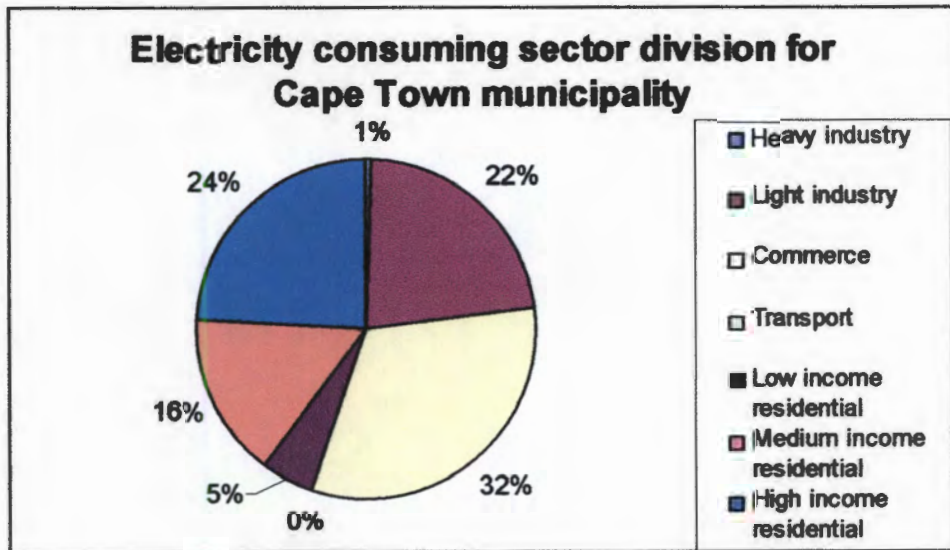


Figure 9-1 Electricity consumption by sector for Cape Town municipality

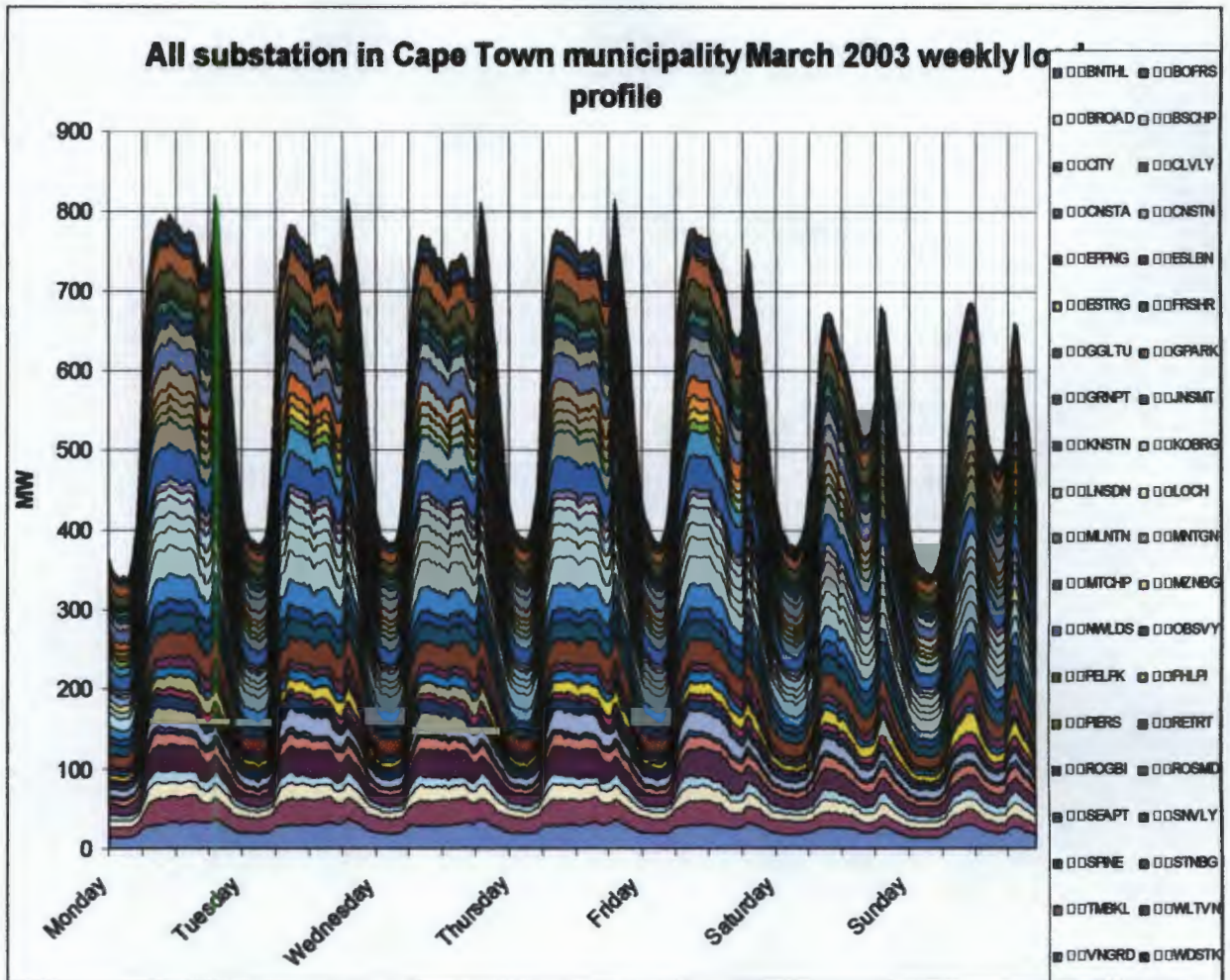


Figure 9-2 Total load profile for all substations in Cape Town Municipality summer 2003

The typical summer peak is 820 MW and it occurs during weekdays, Monday to Thursday, at 19:30. The evening peak observed is due to residential customers increased electric load usage during these times. The summer reduction in peak usage is due mainly to less utilisation of heating load such as cooking, water heating and space heating from residential customers. The minimum demand usage for a typical summer week is very slightly lower than that of a typical winter week. There is a significant morning peak on weekends that can also be attributed to residential customers. The large morning and afternoon daily demand is from commercial and light industrial load activity. The weekly load factor for a typical summer week is 0.73 which is slightly more constant than winter weekly load profiles.

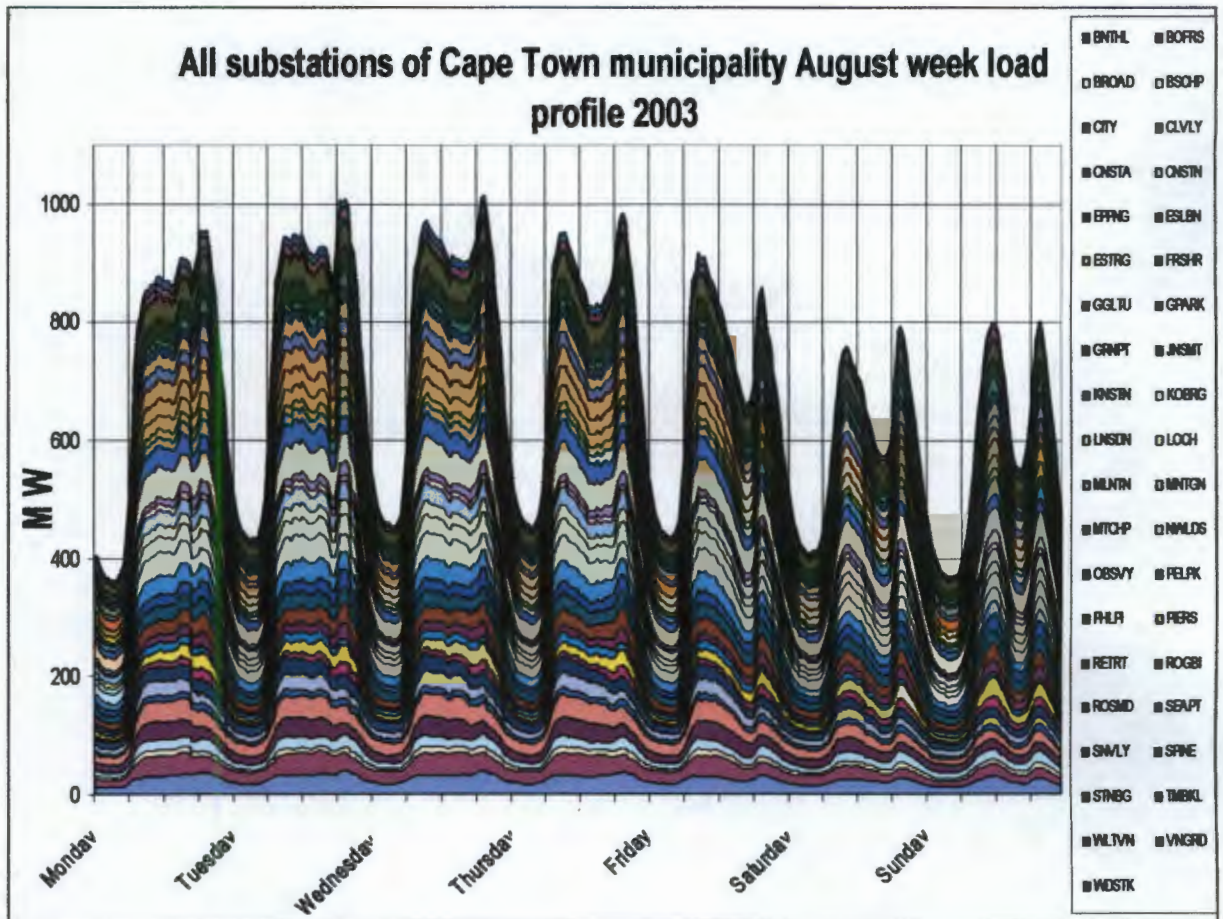


Figure 9-3 Total load profile for all substations in Cape Town Municipality winter 2003

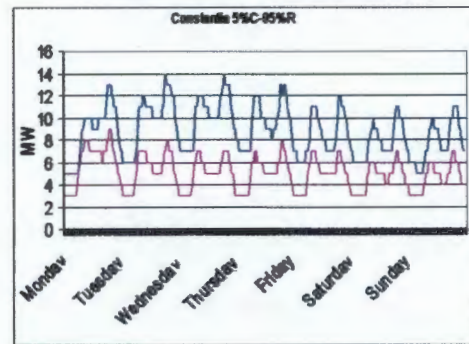
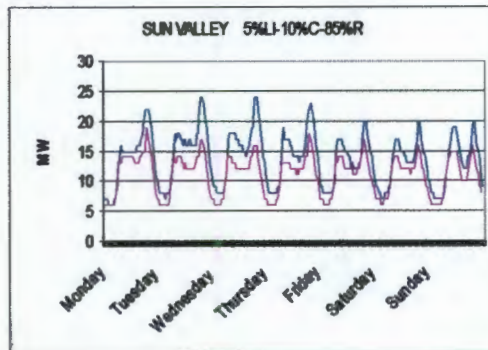
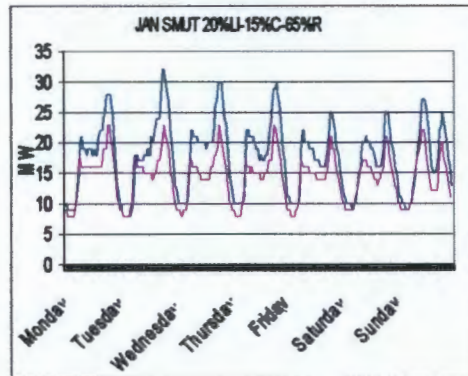
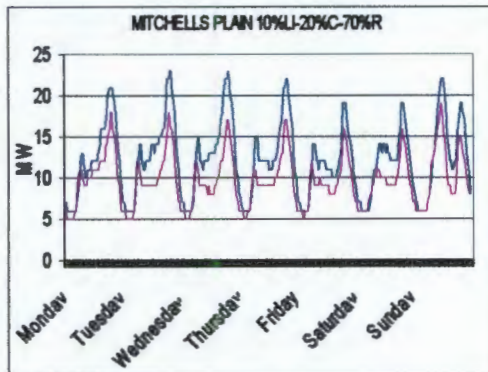
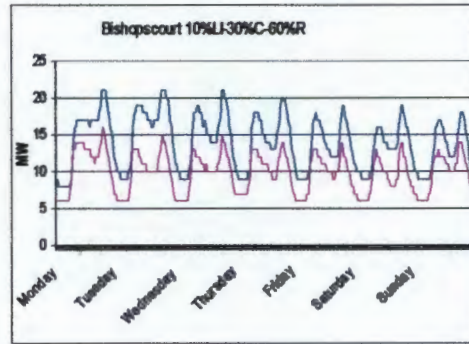
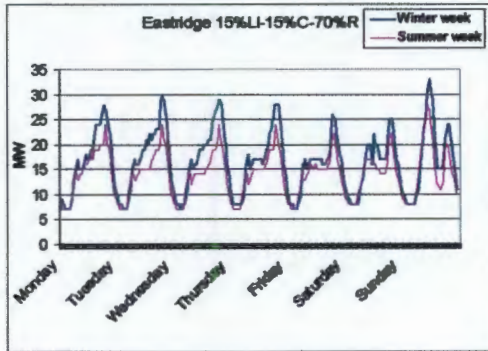
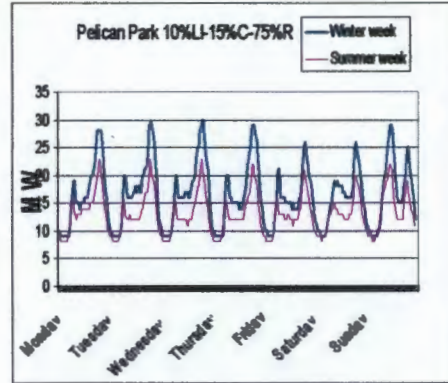
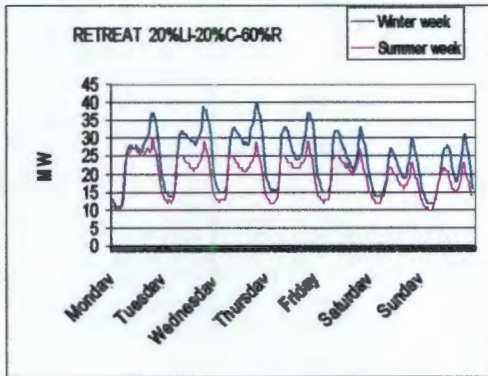
The typical winter peak of the combined load profiles is over 1000 MW and occurs on Wednesday between 18:30 and 19:30. The minimum load required for this week was 365 MW occurring on Monday morning between 2:00 and 3:00. The peak winter week would have a higher maximum demand at a similar time during the day. The weekly load factor for the typical winter week is 0.69.

Sub-stations with at least 60% of their sales coming from a particular sector were selected to build the profiles for that sector. The number of sub-stations used is:

- Residential: 16 stations
- Commercial: 4 stations
- Light industrial: 3 stations

The profiles are shown below:

Where: LI = Light Industry, C = Commercial, R = Residential



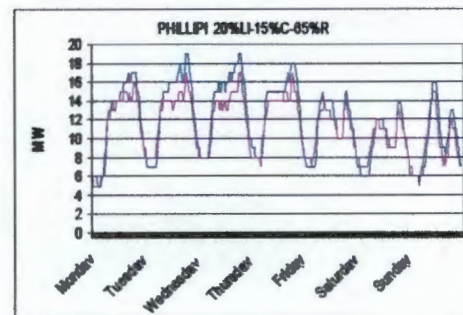
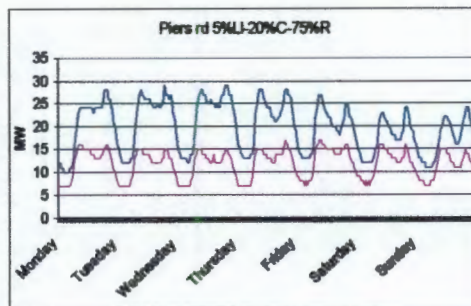
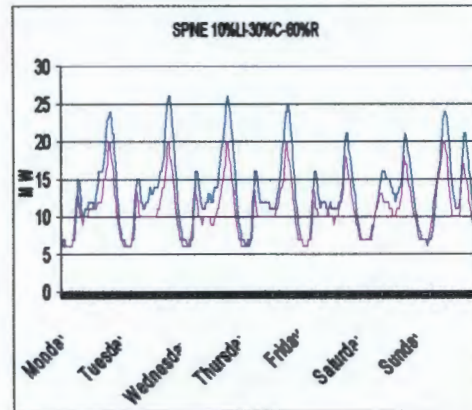
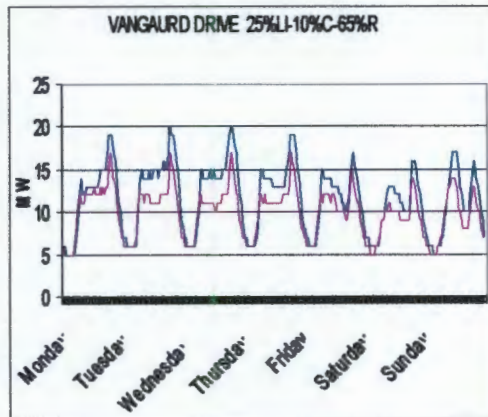
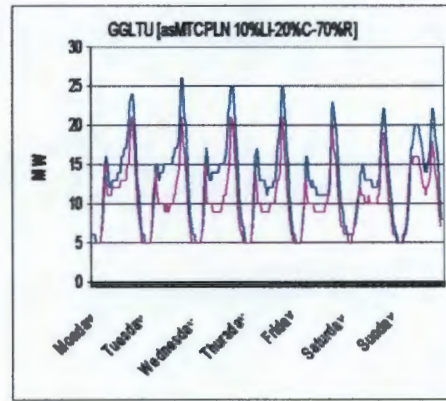
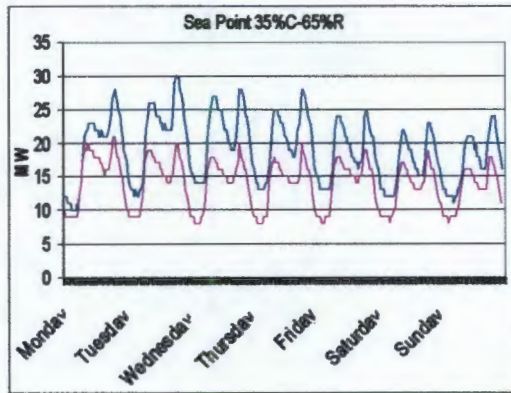
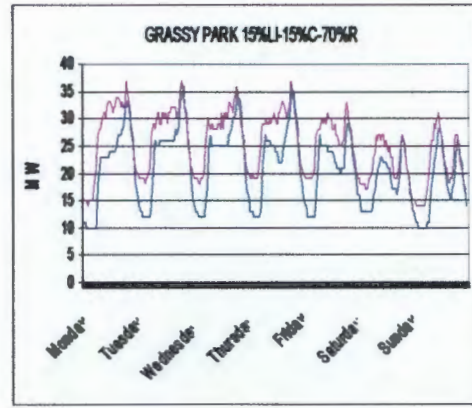
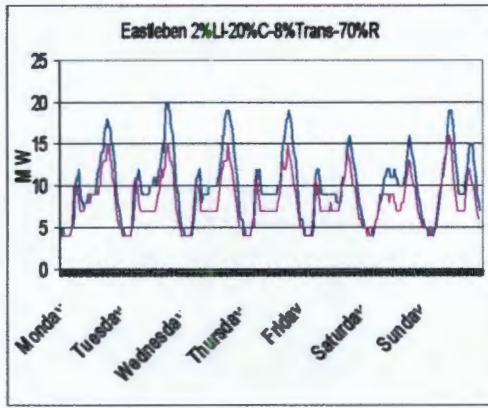


Figure 9-4 Cape Town substations profile used for residential profile (1-16 figures)

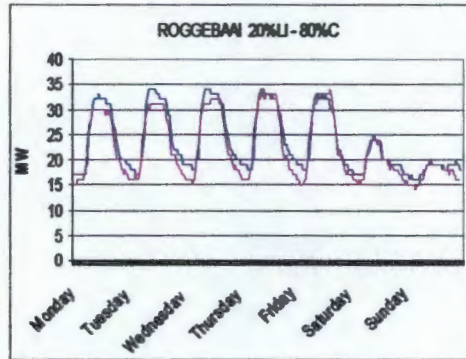
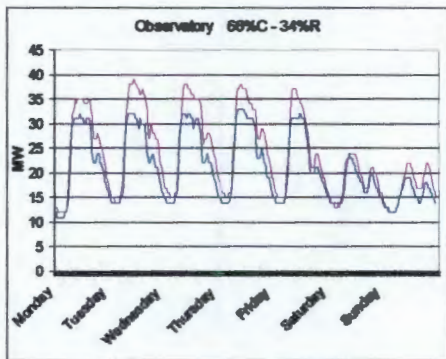
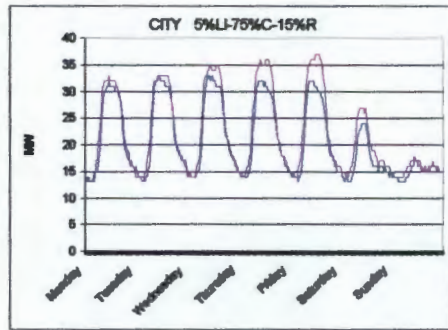
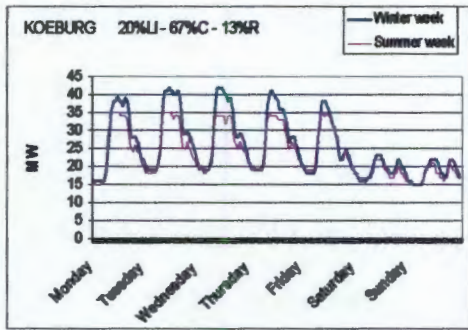


Figure 9-5 Cape Town substations profile used for commercial profile(1-4 figures)

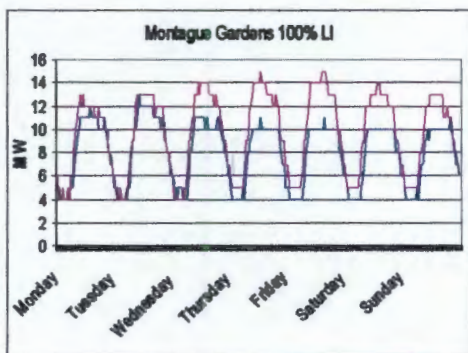
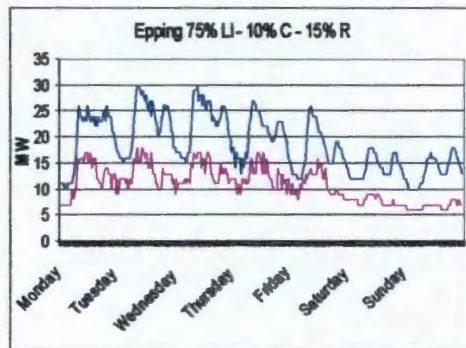
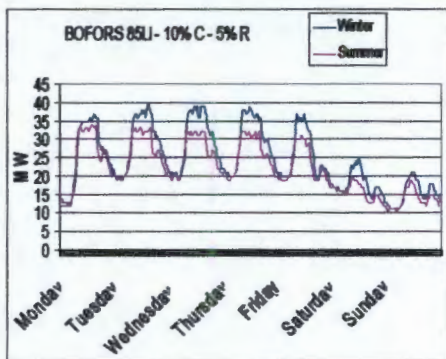


Figure 9-6 Cape Town substation profiles used for industrial profile(1-3 figures)

9.3.1 Filtering methodology

The unwanted sector contribution is filtered out using filter profiles. Each filter profile is used to divide the substation profile into sector categories. The criteria for choosing representative filters are that there should be over 80% sales revenue from that particular sector and that the peak demand should be sufficiently large such as above 20MW. The amount of electricity (% of total MWh) that is used for the residential, commercial and industrial sector is known for each sub-station's weekly demand profile. The total weekly energy for each substation is the area under the curve in the power/time diagrams. Addition of the peak power of all time intervals will represent the actual power consumed more accurately when using smaller time intervals such as half hour instead of hour intervals.

$$\text{Total weekly energy [MWh]} = \sum (\text{Hourly peak demand [MW]})$$

The filter calculation is operated on each peak power value for each time interval.

$$\text{PowerSectorA}_{ti} = \text{TotalPower}_{ti} - \text{PowerSectorB}_{ti} - \text{PowerSectorC}_{ti}$$

Where PowerSectorA_{ti} is the hourly power peak for Sector A

PowerSectorB_{ti} is the power contribution from sector B

PowerSectorC_{ti} is the power contribution from sector C

$$\text{PowerSectorB}_{ti} = \text{MultiplierB} * \text{per unit filter profile for sector B}$$

$$\text{PowerSectorC}_{ti} = \text{MultiplierC} * \text{per unit filter profile for sector C}$$

The multiplier is the order of magnitude that the per unit filter profile must be increased by until all sales from that sector are accounted for.

9.3.2 Commercial Profiles for Cape Town

The commercial profile is first calculated because of the fewer substations used. Residential and industrial filter profiles are needed to remove their contributions from these substations. The filter profiles are shown below.

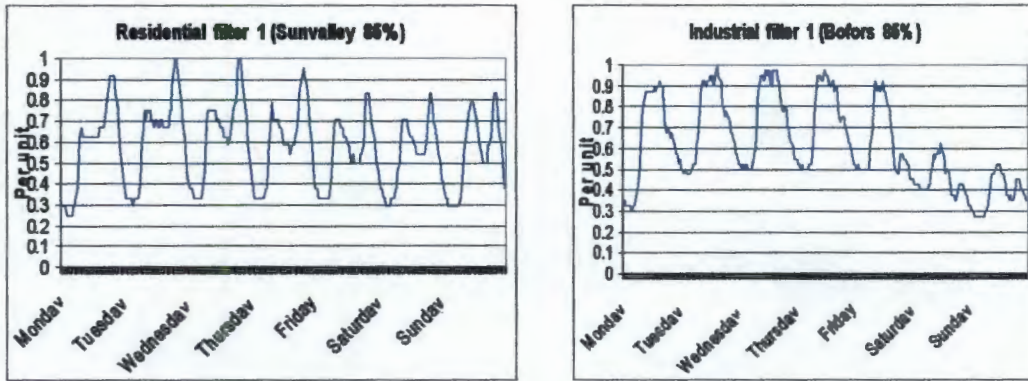


Figure 9-7 Residential and Industrial filters

The filter profiles are per unit profiles and their magnitude is increased until the total energy that is accounted for, is equal, within less than 0.1% error, to the sales from that sector. The area under the curve is the amount of energy that is consumed by that sector.

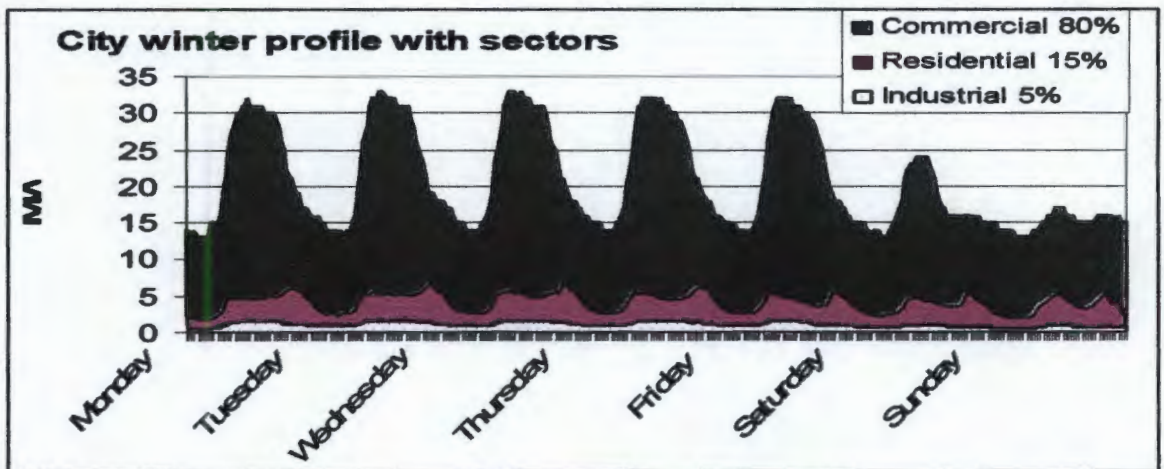


Figure 9-8 City typical winter week profile divided into sector contributions.

Each substation profile for typical winter and summer weeks are divided into sector contributions and profiles representing commercial loads remain when the other sectors are removed. The profiles of the commercial loads for the three mostly commercial substations are shown below.

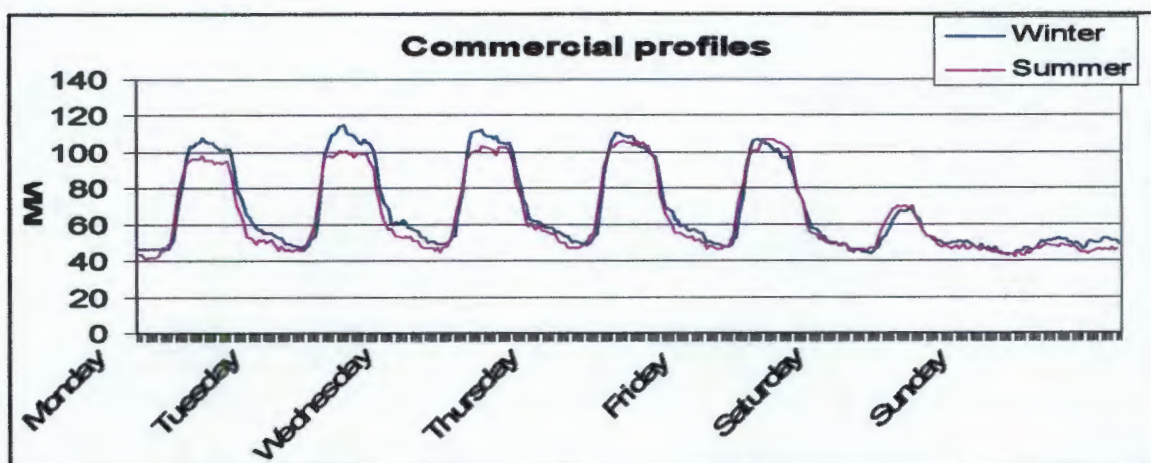


Figure 9-9 Commercial profiles for typical summer and typical winter weeks.

Per unit profiles are then calculated so that the commercial profile for summer and winter weeks can be used as a filter to remove commercial components from mostly industrial and residential substations.

The filtered load profile for the commercial sector indicates what is expected from commercial activities. There is a daily pattern of electricity use with peaks between 8:00 and 20:00 on weekdays. The minimum load of 46% peak load is maintained throughout the week but the weekend peaks are only slight with Saturday larger than Sunday. The weekly load factor is 0.62 for summer weeks and 0.6 for winter weeks which is common for commercial profiles. This profile could be used to represent a commercial load profile for other municipalities with similar commercial activities. The accuracy of extrapolation to represent larger and more diverse areas will depend on the amount of measured data and its reliability.

9.3.3 Industrial Profile for Cape Town

There are 3 mostly industrial substations supplied by Cape Town Municipality. The industrial customers supplied from these substations are all light industry. The unwanted sector contributions in these substation profiles are removed in the same way as for the commercial profile. The commercial filter profile is already calculated and the residential filter profile uses the profile from Pelican Park substation. Pelican Park profiles were chosen instead of the previously used residential filter profile (Sun Valley) because of its

higher industrial contribution and its 75% residential sales. The total winter week profile for the substations with sector contributions is shown below.

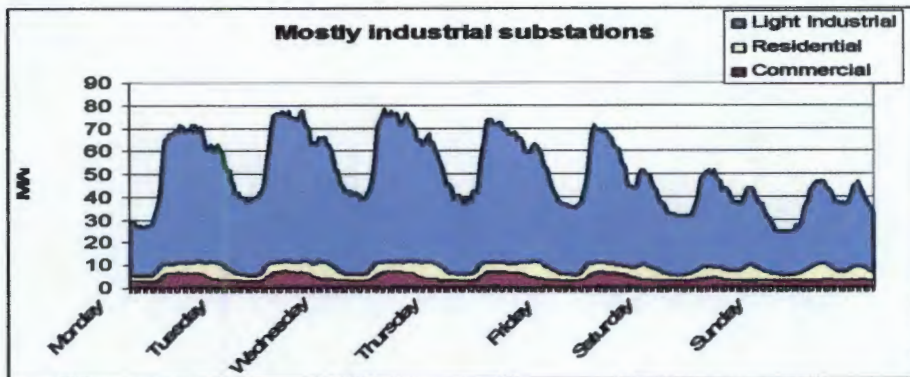


Figure 9-10 Mostly industrial substations typical winter week profile

There is still a large residential component within the industrial profile, as can be seen from the evening peak and the weekend profile in the figure above. This contribution is removed using a profile filter with a large inverted (negative) residential shape. The residential component is magnified until the industrial profile has no residential component. The per-unit light industrial load profile is shown in the figure below.

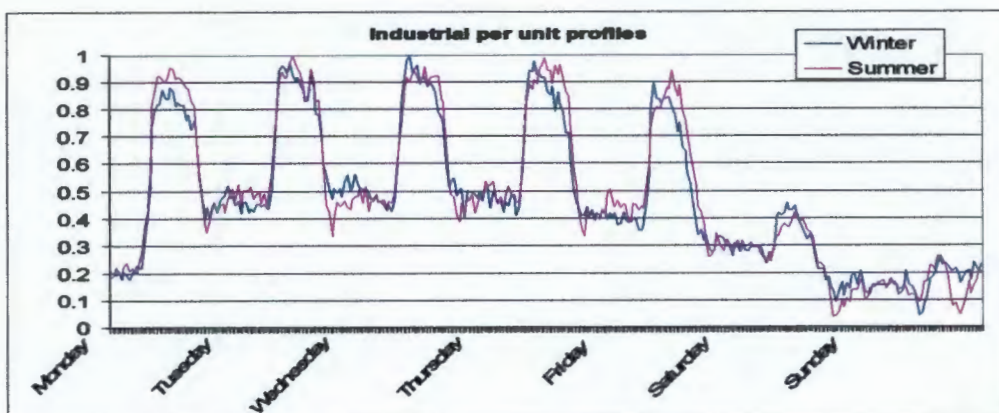


Figure 9-11 Industrial customer consumption pattern for Cape Town

The light industrial load is basically a square wave with flat peaks during normal working hours which are typical of small processing entities.

9.3.4 Residential load profiles for Cape Town

The residential substations use the calculated commercial and industrial profiles as filters to remove commercial and industrial components from each profile. The remaining profile after filtering is a residential profile. Each of the 16 load profiles is filtered to retrieve the residential component. An example of the segmentation of a substations load profile is shown below.

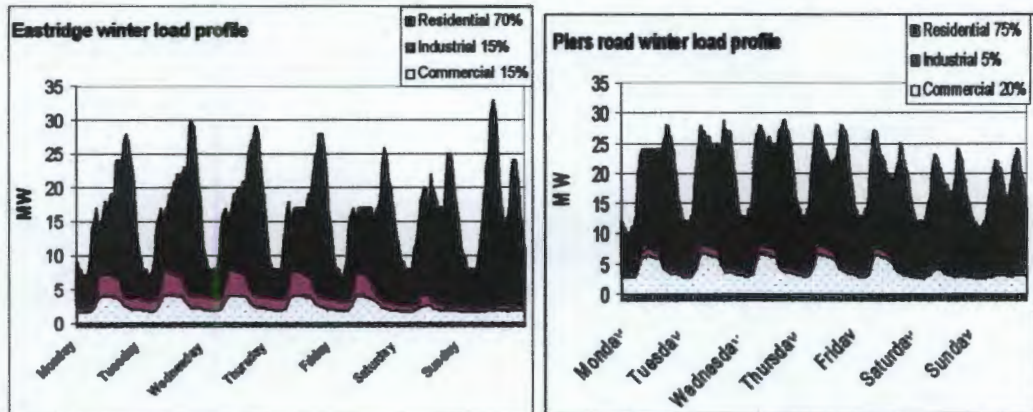


Figure 9-12 Example of sector segmentation of Eastridge and Piers road winter load profile

The shape of the residential load profiles for Eastridge differs significantly from that of Piers road. The reason is that the pattern of consumption differs in low income household to higher income houses. Low and medium income residential load have lower morning peaks, high evening peaks and Sunday morning is when the maximum peak load occurs for all seasons. High income residential loads have similar morning and evening peaks. The Eastridge residential load that accounts for 70% of the energy consumption is further divided into 30% low income, 30% medium income and 10% high income. The Piers road residential load that accounts for 75% of the energy consumption is further divided into 0% low income, 5% medium income and 70% high income [3]. The weekly load factor is a measure of the flatness of the load profile for a single week. It is calculated using the formula below.

$$\text{Weekly load factor} = \frac{\text{Total weekly electricity consumption (MWh)}}{[(\text{Maximum peak demand during week MW}) * (168 \text{ hours/week})]}$$

The weekly load factor of the residential profile of Eastridge for both summer and winter weeks was 0.39. The weekly load factor of the residential profile of Piers road for both

summer and winter weeks was 0.61. The yearly load factor takes monthly variations into account and will be lower because of the peaky nature of the yearly load profile for the residential sector.

The total residential component for summer and winter weeks from all the mostly residential substations is shown in the figure below.

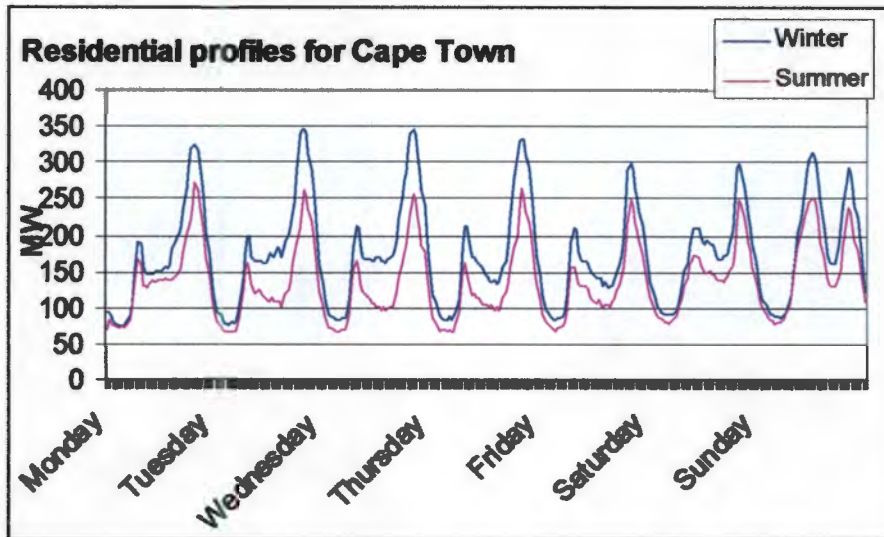


Figure 9-13 Residential load profiles for mostly residential sub-stations in Cape Town

The shape of the total residential profile for the sub-stations used resembles a low/medium income residential load profile more than a high income residential load. The residential component of the total electricity sales for the set of mostly residential substation is 70% in both typical summer and winter weeks. Total electricity sales to low and medium household is 60% of the total residential electricity consumption for the chosen stations. The profile is thus a mostly low to medium income residential load profile. The chart below shows the residential customer split for customers supplied by Cape Town municipality (CT).

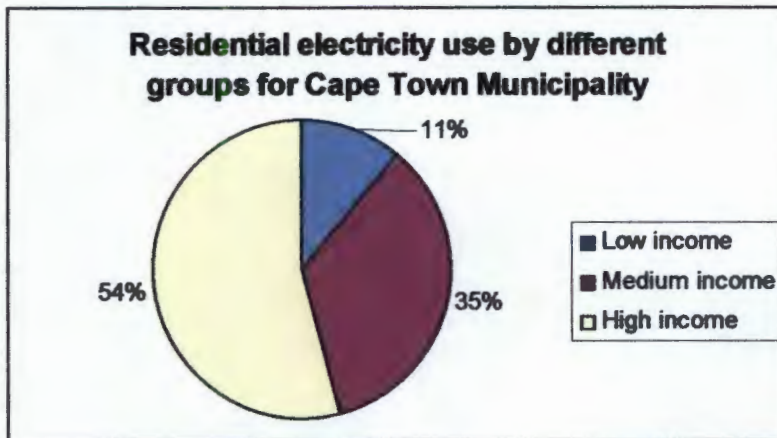


Figure 9-14 Residential customer split of electricity sales supplied by Cape Town municipality

The calculated profile for all residential consumers supplied by CT would look slightly different as there would be a large contribution by higher income users and typically this would mean a higher morning peak on weekdays and a lower Sunday morning peak. A representative profile of the national residential electricity use would have to be defined in terms of household types. Loads such as water heating, cooking, cooling, lighting, space heating and other appliances constitute the electric demand for households. National or municipal data on household classification could provide the correct mix to compile a representative load profile. Databases of electricity patterns of case studies and selected energy audits could provide accurate load profiles.

There is a 25% increase in peak power consumption for winter week because residential loads are more temperature dependent than other sectors. Per unit profiles of typical winter and summer weeks are calculated.

9.3.5 Industrial load profile iteration

Accuracy of the Industrial profile is improved by using the calculated residential load as the filter profile instead of a substations load profile. The same filtering methodology is followed and the new industrial load profile is shown below.

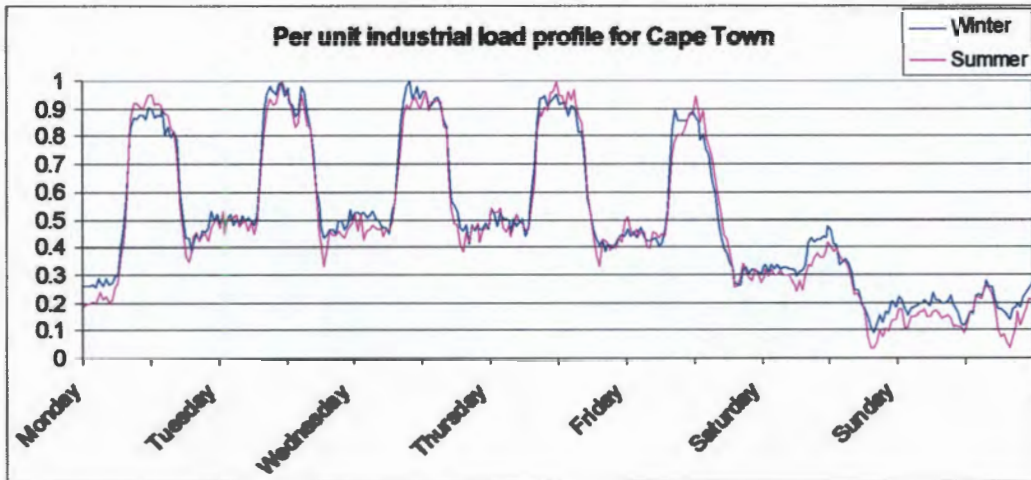


Figure 9-15 Industrial load profiles from iteration

Even though the shape of the profile for winter is similar to that of summer the magnitude of the load profile increases by approximately 10% in some months and there is no large temperature dependency as with residential load. The weekly load factor is 0.5.

9.4 Load profiles for sectors in Tshwane

The profiles collected from Tshwane municipality electricity department were in per unit form for a large variety of sectors. It is assumed that the profile for Monday to Friday is the same for all sectors. Saturday and Sunday have their own separate daily profiles. The load profiles are already by each sector and some sub-sectors. The profiles are included in the report as a comparison to the profiles calculated from Cape Town substation so that accuracy can be ensured when representing national sectors.

9.4.1 Residential

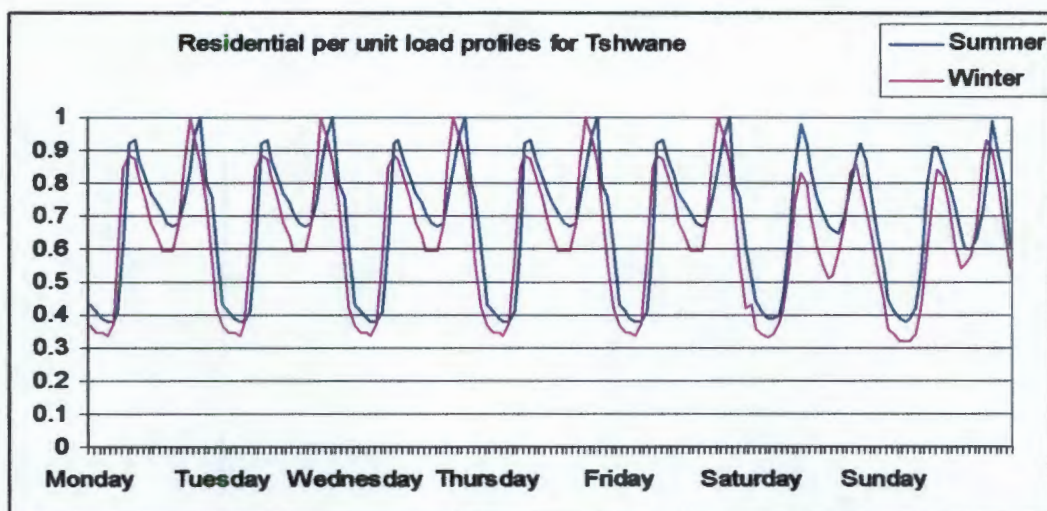


Figure 9-16 Seasonal residential load profiles for Tshwane

The residential profile for Tshwane has a higher morning peak and a lower Sunday morning peak than the CT residential profile. This is due to the Tshwane profile representing all users, both low and high income. It is suspected that there is a significantly larger high income contribution than by low income users as the weekly load factor is high at about 0.65 and more reflective of a commercial load factor.

9.4.2 Commercial and public services

The profiles included under the commercial and public sectors sector include similar activities within the sector:

- Commercial
- Education
- Tertiary Education
- Municipal ,Government and other buildings
- Businesses and Offices

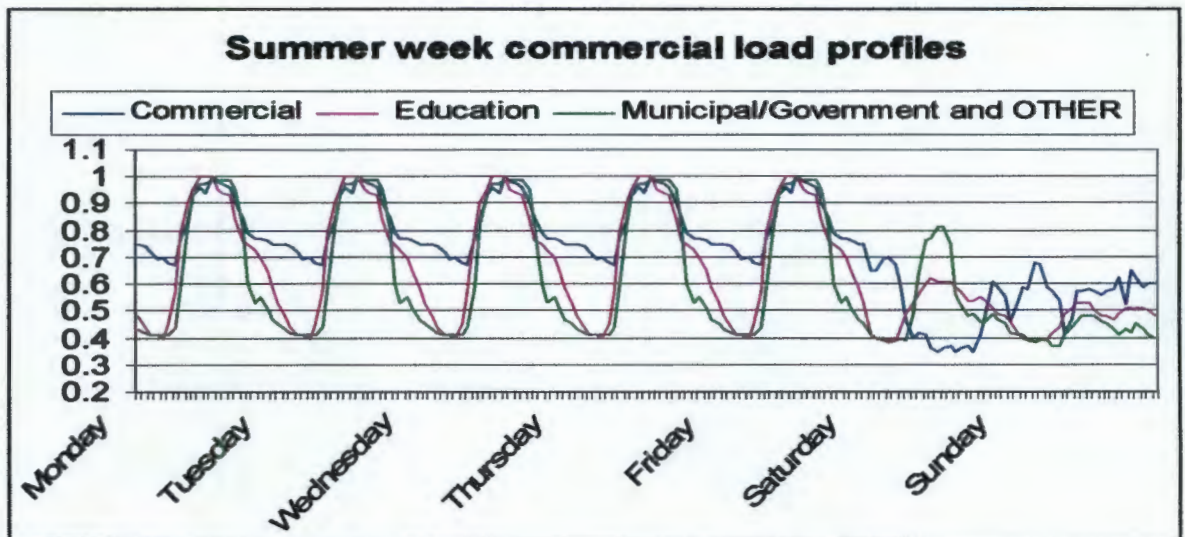


Figure 9-17 Summer week commercial load profiles for Tshwane

The most constant profile, commercial, has a minimum of 70% of the peak while education and municipal/government have 40% minimum load utilisation in the per unit profiles.

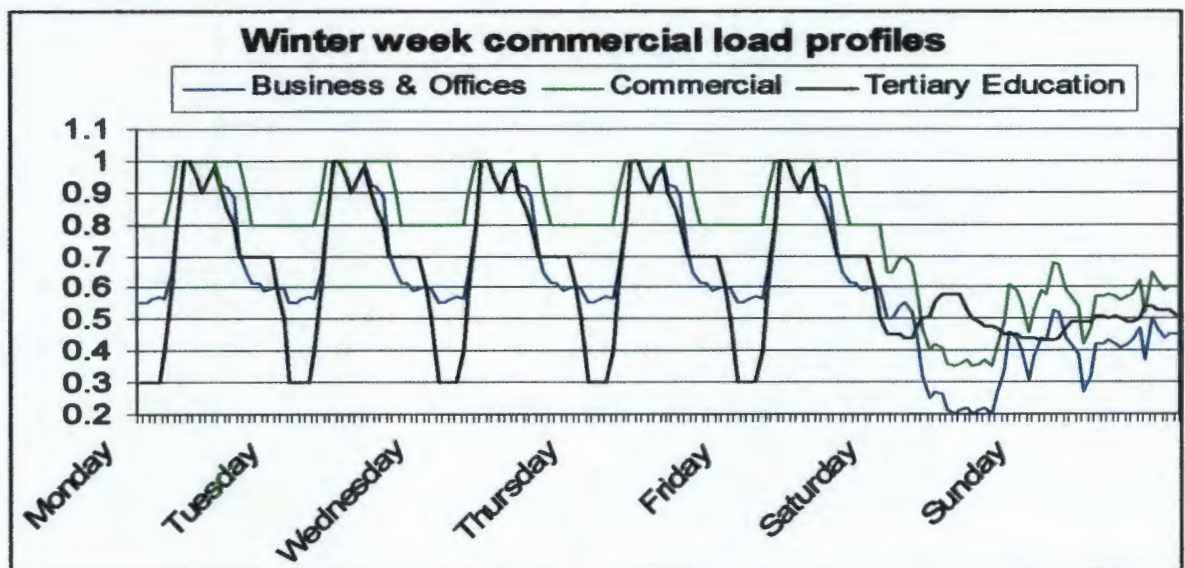


Figure 9-18 Winter week commercial load profiles for Tshwane

Commercial load profiles are the most constant and have a minimum load usage of 80%. Businesses and offices having a reduced minimum load of 55% and tertiary education a further minimum peak reduction at 30% load utilization. The six commercial profiles in the above figure represent the different types of activity included in the commercial sector. The load profiles labelled “commercial” are more industrial looking and they could be reflective of small industrial activity within the commercial sectors such as car service repairs or

service shops with constant operating loads. The remaining load profiles are more dependent on day-time electricity use typical of regular commercial activities. The per unit load profiles for municipalities and government buildings as well as education have more fluctuation in their consumption patterns in comparison to commercial, businesses and offices electrical usage which have flatter maximums and minimum peaks

	winter week LF	summer week LF
Commercial	0.74	0.79
Business & Offices	0.64	-
Education	-	0.65
Municipal / Government and OTHER	0.62	0.61
Tertiary Education	0.64	-

Table 9-2 commercial load factors

9.4.3 Industrial

Industrial electrical loads can be operated using different demand profiles:

- Typical industrial loads
- Mostly flat or constant loads with weekend and no weekend reductions
- Loads operated according to a time-of-use tariff structure

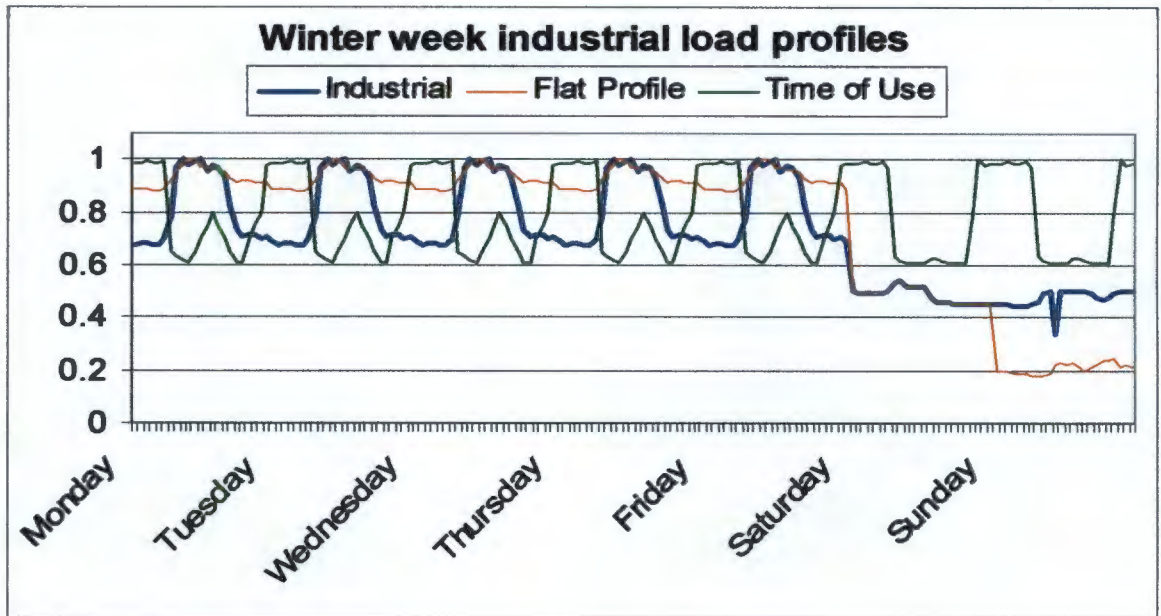


Figure 9-19 Winter industrial load profile for Tshwane

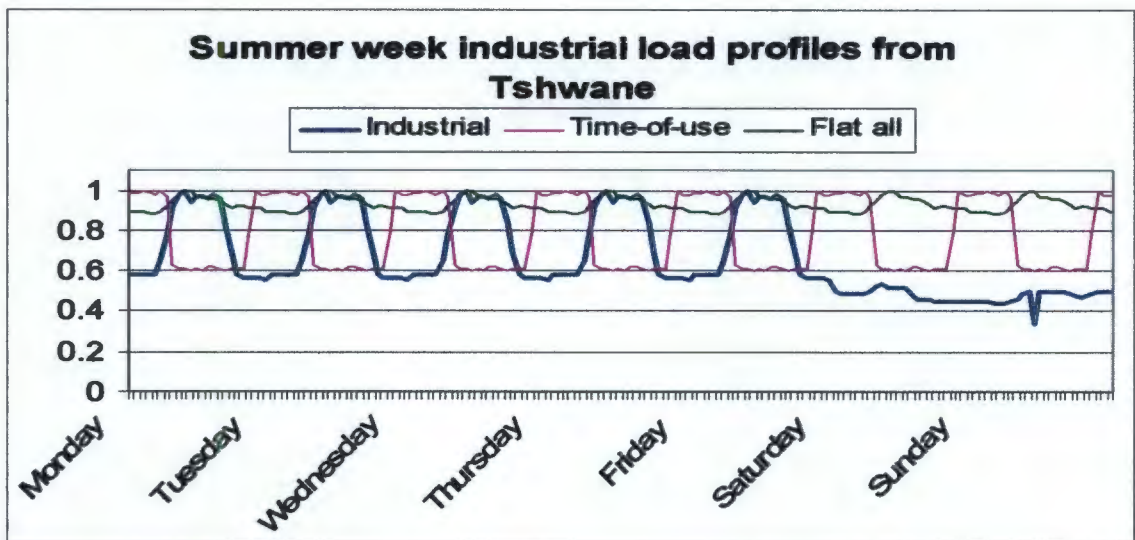


Figure 9-20 Summer industrial load profiles for Tshwane

There are 3 types of industrial profiles given, such as a typical industrial load profile, a flat profile and a time-of-use profile that can be used to represent single or sectoral industrial activities. A fourth profile is calculated for loads that have a flat profile throughout the whole week and there is no lowering of demand on weekends. These profiles represent different types of industrial activity specific to the type and size of loads. Light industry electricity consumption patterns, as calculated for Cape Town, is most similar to the industrial profiles for Tshwane in the 2 figures above. Large industries would have a significant proportion of

their loads on flat cycles if there are continuous working shifts or on time-of-use operation for loads that can be shifted to specific times.

9.4.4 Agriculture

Agricultural load profiles include:

- Farm land used for commercial farming
- Agricultural holding with less farming activities

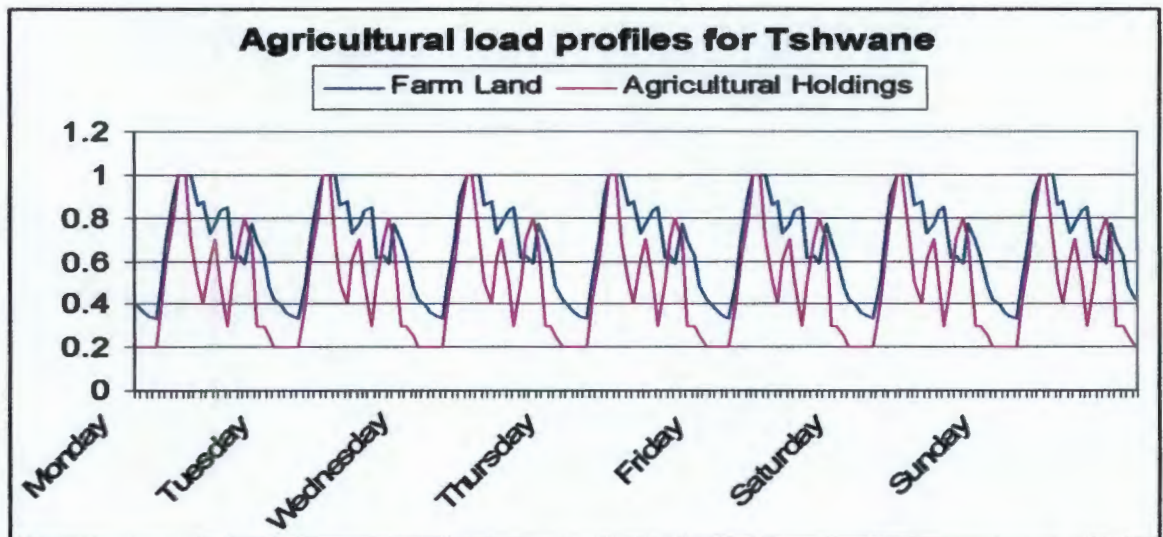


Figure 9-21 Load profile for Agricultural activity in Tshwane

These load profiles for agriculture are for winter seasons and are also used for summer months by accounting for the change in demand peak. The profile shows a morning peak which is reflective of farming activity. There is also a large evening peak because of the domestic demand by those residing on farms. The weekly load factor for the farm lands profile is 0.5 and for agricultural holdings 0.67.

9.4.5 Yearly consumption for Sectors

The per unit profiles calculated above are used to build yearly profile of electricity demand for the different sectors. The monthly variation in peak demand is either temperature dependant or activity related or a combination of both. The planning division of Tshwane electricity department uses these yearly demand profiles.

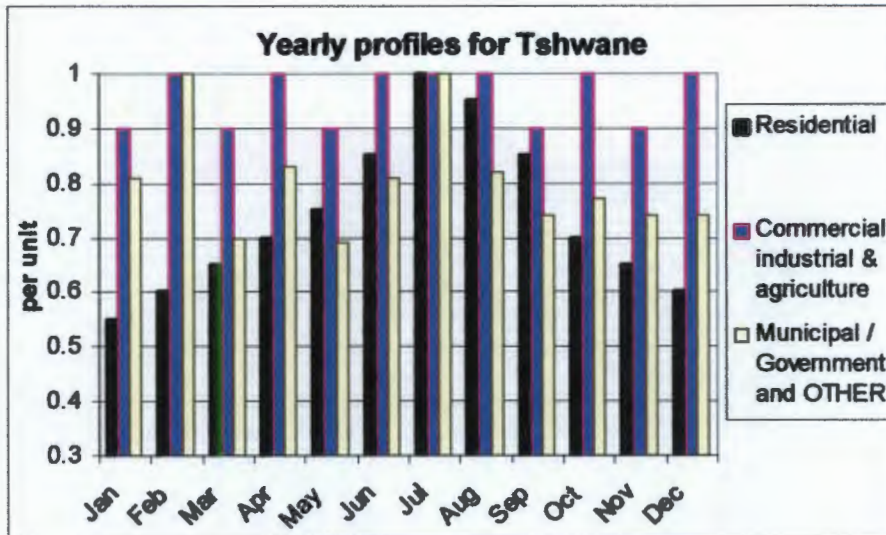


Figure 9-22 Yearly variation in peak demand for sectors

9.5 Conclusion and recommendation

A better understanding of demand for electricity is gained by viewing how sectors use loads at different times of the day and year. The residential, commercial and light industrial sectors have more demand variations than larger industries.

A representative load profile of the entire sector could be calculated if the proportionate electricity consumption is known from each activity and their related load profiles constructed. An analysis of the types of commercial activities, for instance, could be conducted with the aim of weighting the load profiles from each sub-group to represent a particular sector's consumption patterns. An end-use analysis would provide further ability to divide the load profile into the actual load usage over time.

The individual sector load profiles form a basis for locating areas where DSM programs are needed the most. The residential, commercial and light industrial sectors have the lowest load factor. The commercial and light industrial sectors contribute mainly to the morning peak on the system and the residential sector to the evening peak on the system. The system peaks could be most affected with DSM programs in these sectors.

The sector load profiles can be used as a tool to view the effects of any program to change the type of load or demand. The profiles will be used in energy models for optimising supply and demand side planning.

9.6 References

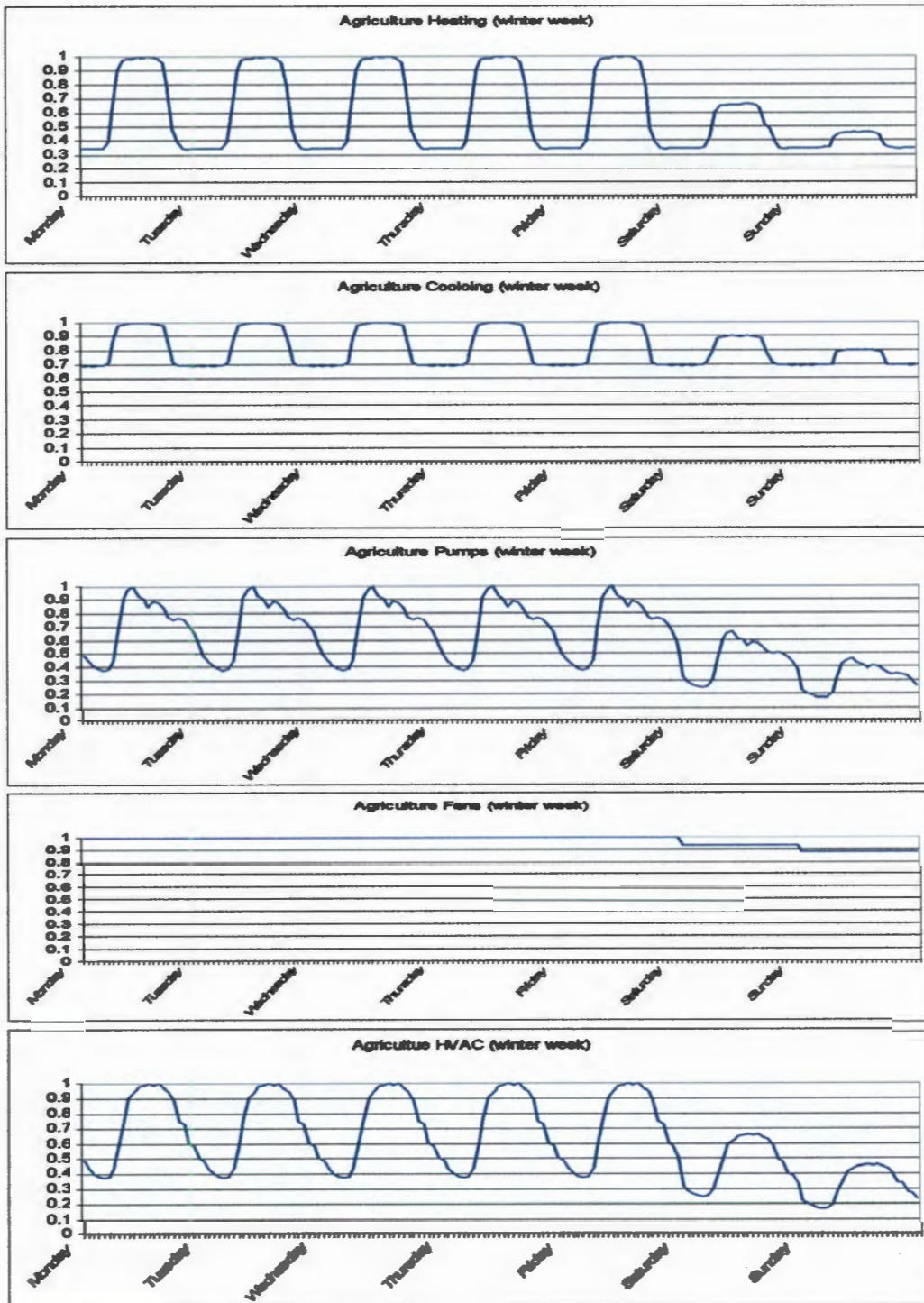
- [1] Cape Town Electricity, Peter Jaeger, telephone no: 021-671-3086
- [2] Tshwane Electricity Department, Coerts Kerman, telephone no:021-308-0434
- [3] "Data for CMA substations", Kudu Gas: Cape power project, Appendix N, PB Power, 1999

10 Appendix B: Electrical End Use per unit Load Profiles.

All the electricity consuming devices have been categorised into the type of end-use they meet. Each sector's electricity use patterns are represented by weekly load profiles for specific loads that are used by that sector. The profiles represent how electricity is used to provide a particular service for all similar load types in a sector. The load profile plots the electricity demand for every hour of the week. The profiles have all been normalised so that only the shape is used and an electric demand (kW) is therefore replaced with per unit values. The per unit profiles were calculated from data used by Eskom DSM department. The data is a collection of end-use weekly load profiles from different sectors for 3 periods of the year namely March, June and September. The data was compiled from a few individual case studies of electricity consumption in different sectors. The per unit profiles are used to build up sectoral load profiles, end-use load profiles and ultimately total load profiles. Demand side analysis is a continuous process as the patterns and technology of electricity use change. Each profile would need to be verified by actual measurements of loads. This study serves as an initial attempt to use more defined demand data for electricity integrated resource planning which incorporated demand side management and energy efficiency programs.

It would be too cumbersome to include both winter and summer weeks from all end-uses and only winter end-use load profiles have been included. Each profile is slightly different and would have more dissimilarity if more measured data was available for loads within each sector. The purpose of enumerating all the profiles is to indicate the complexity of representing all end-uses.

10.1 Agriculture Load profiles



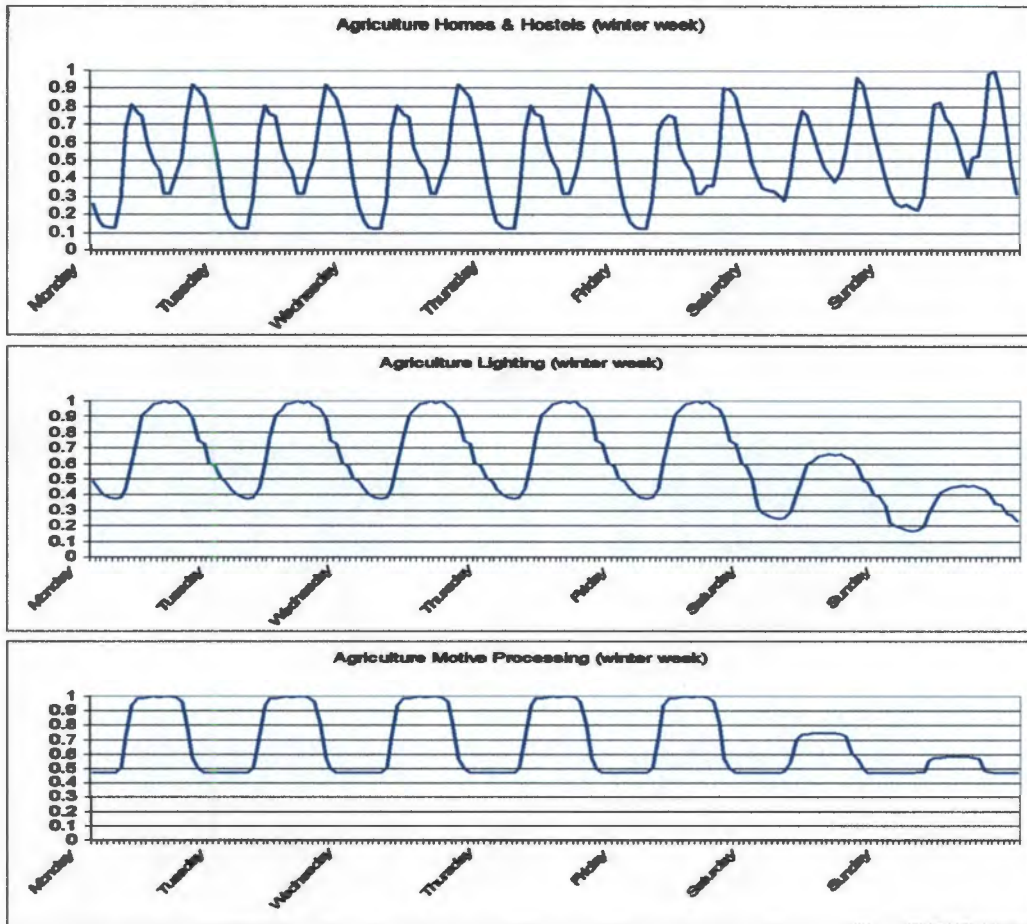
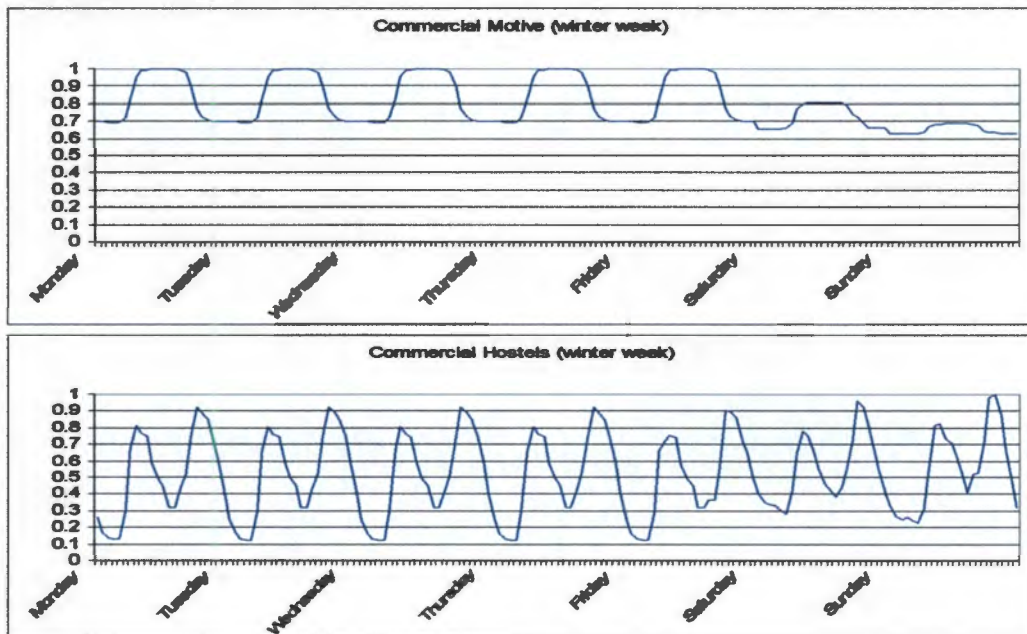


Figure 10-1 Agricultural end-use per unit weekly load profiles (1-8 figures)

10.2 Commercial Load Profiles



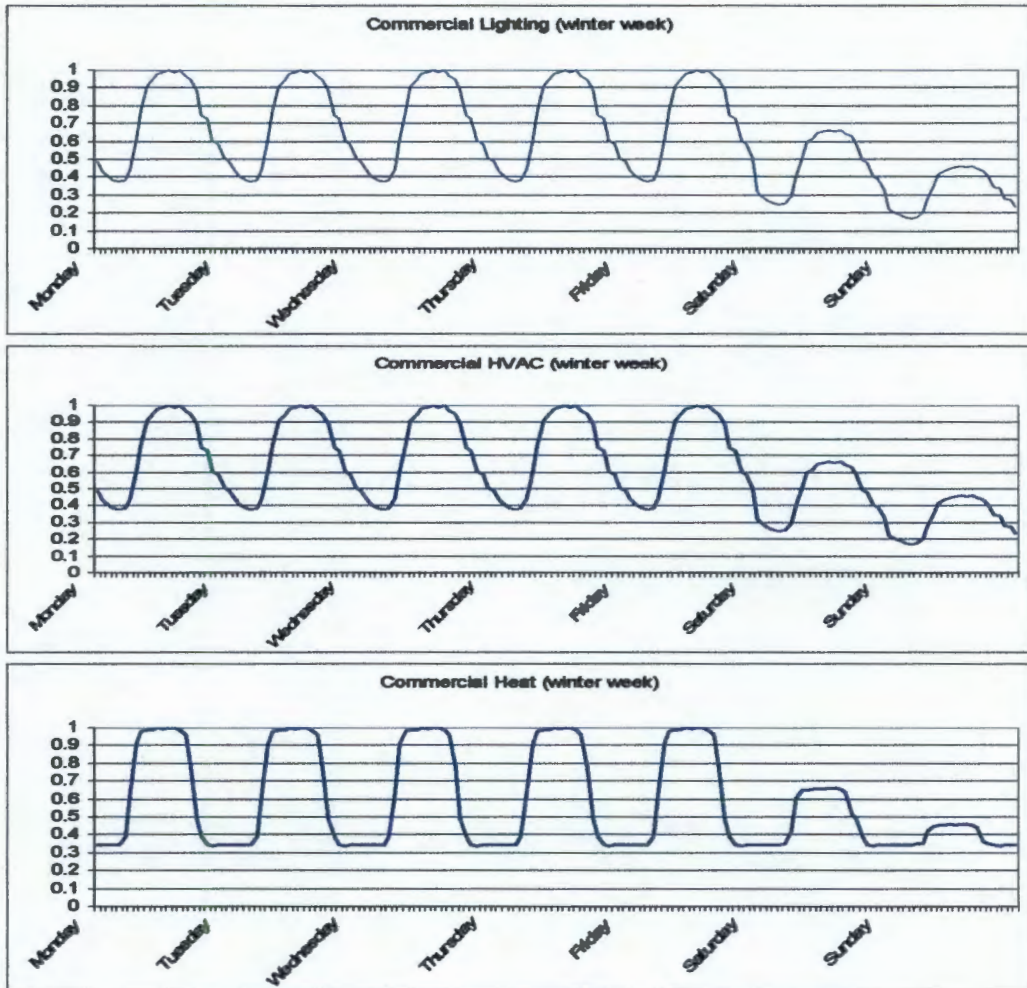
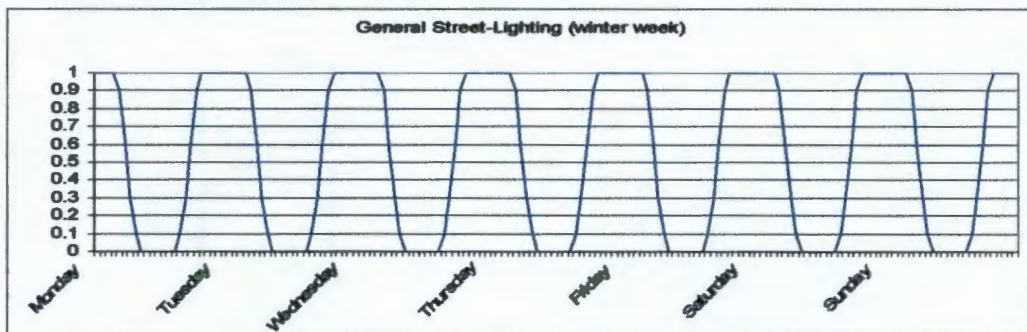


Figure 10-2 Commercial end-use per unit weekly load profiles (1-5 figures)

10.3 General services load profiles



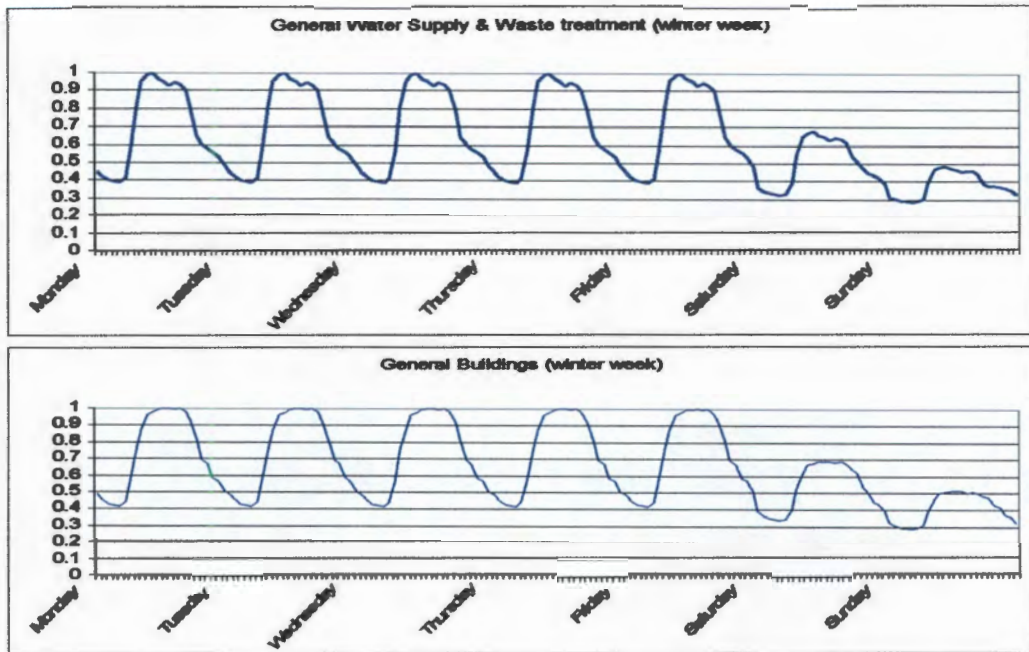
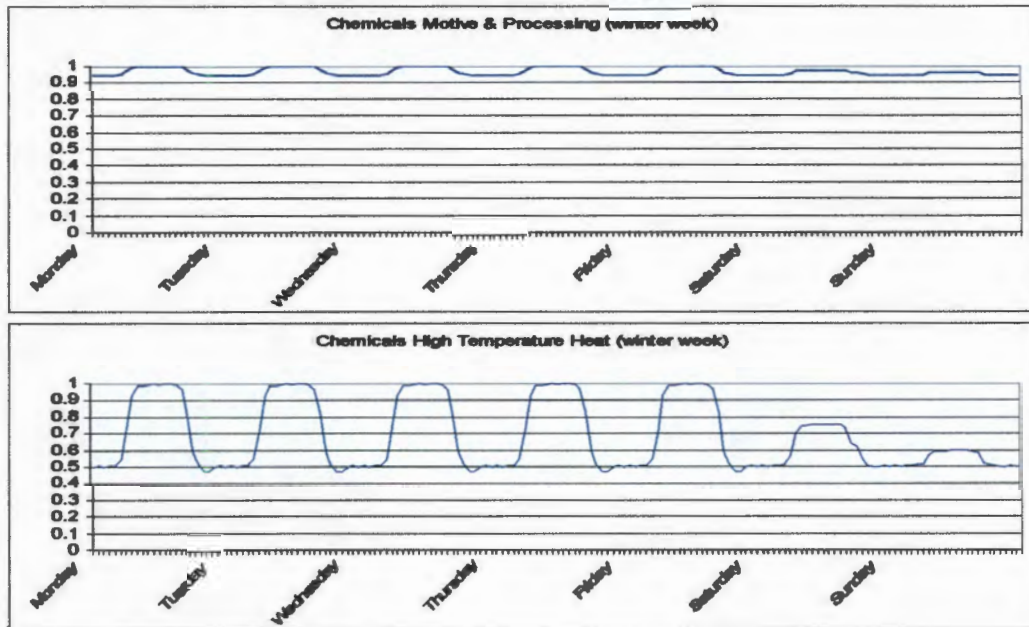


Figure 10-3 General services end-use per unit weekly load profiles (1-3 figures)

10.4 Chemicals & Petrochemicals load profiles



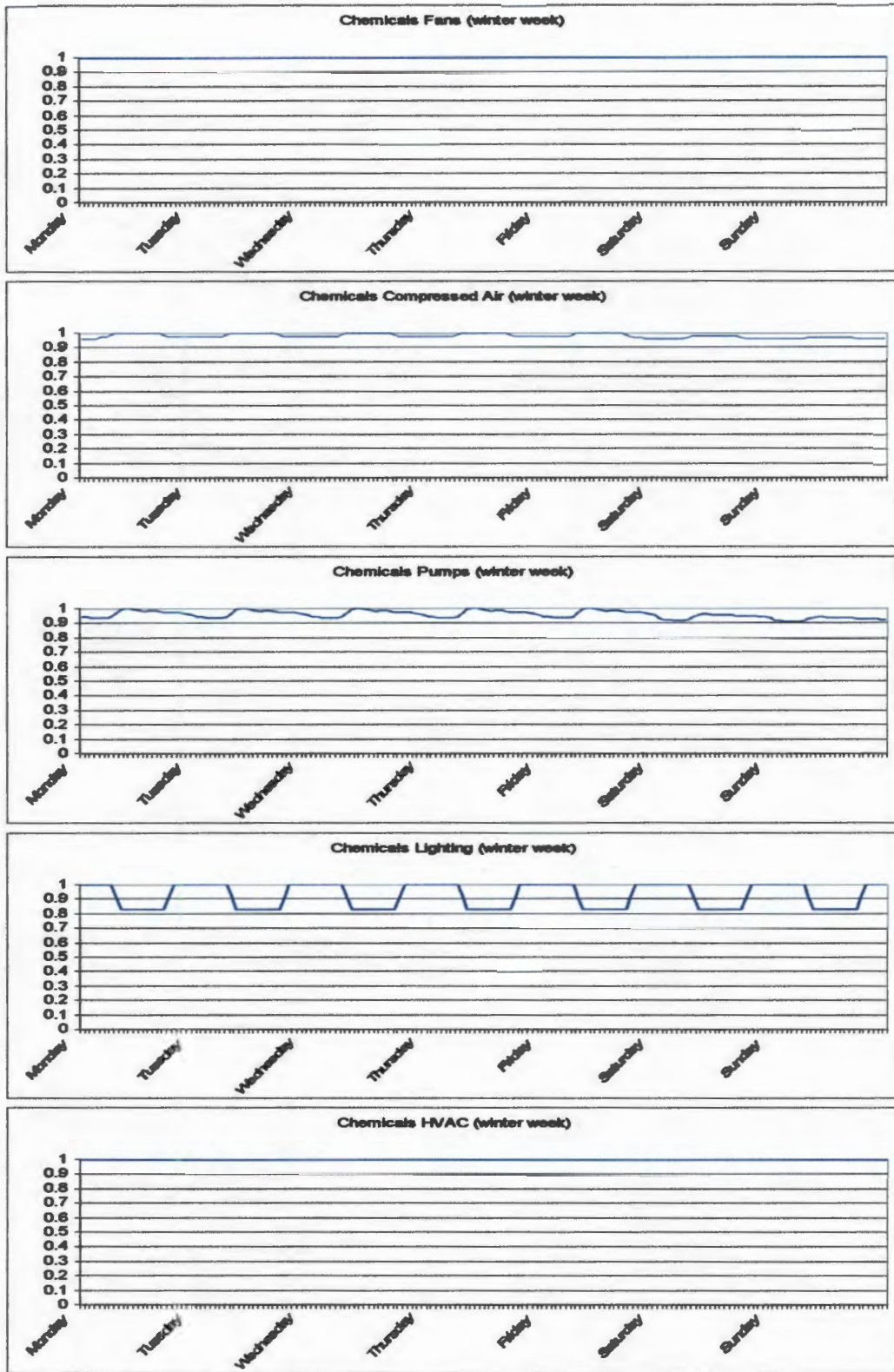
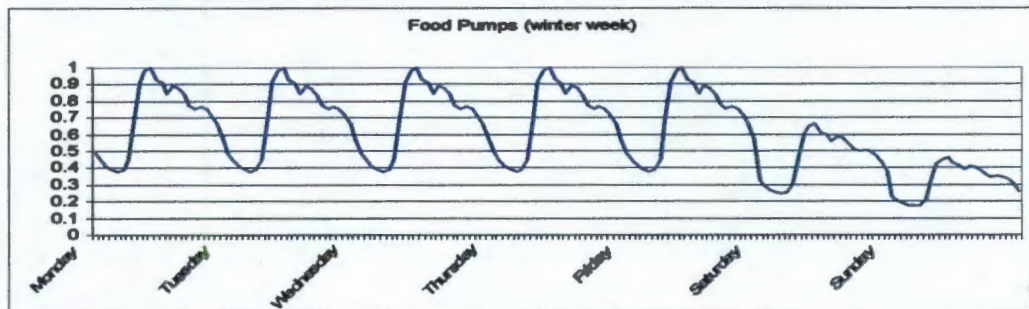
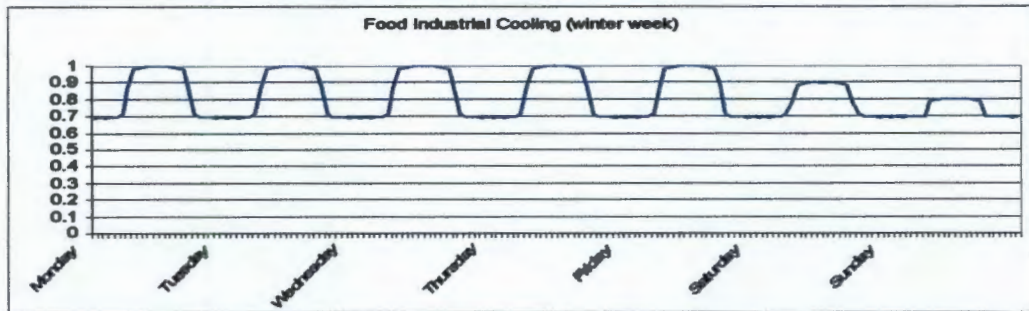
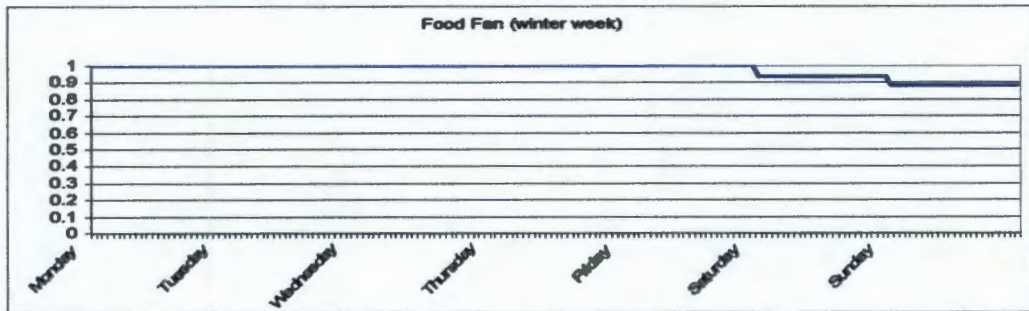
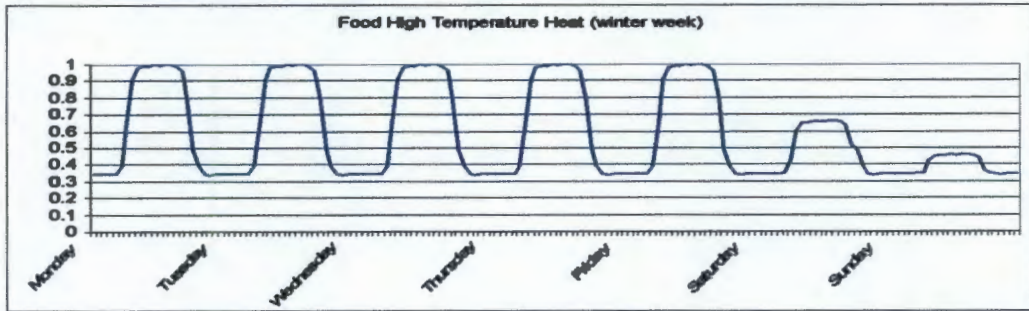
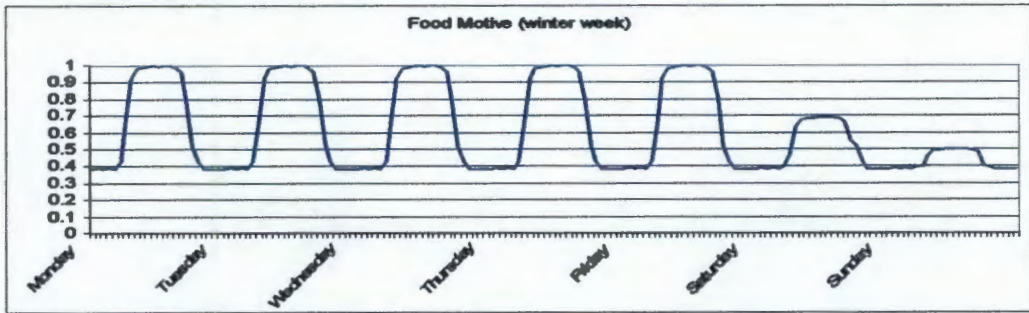


Figure 10-4 Chemicals end-use per unit weekly load profiles (1-7 figures)

10.5 Food load profiles



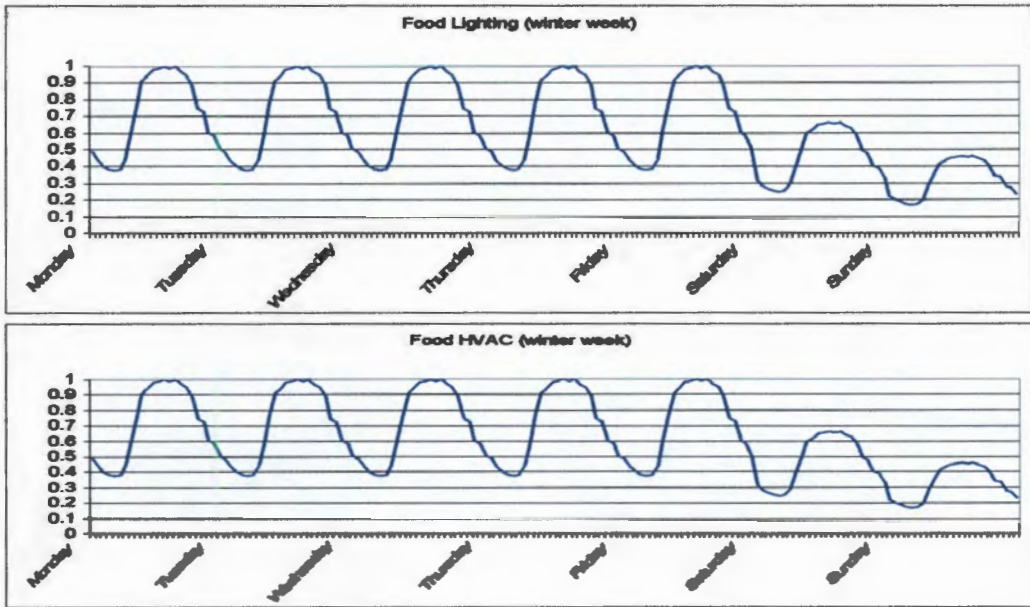
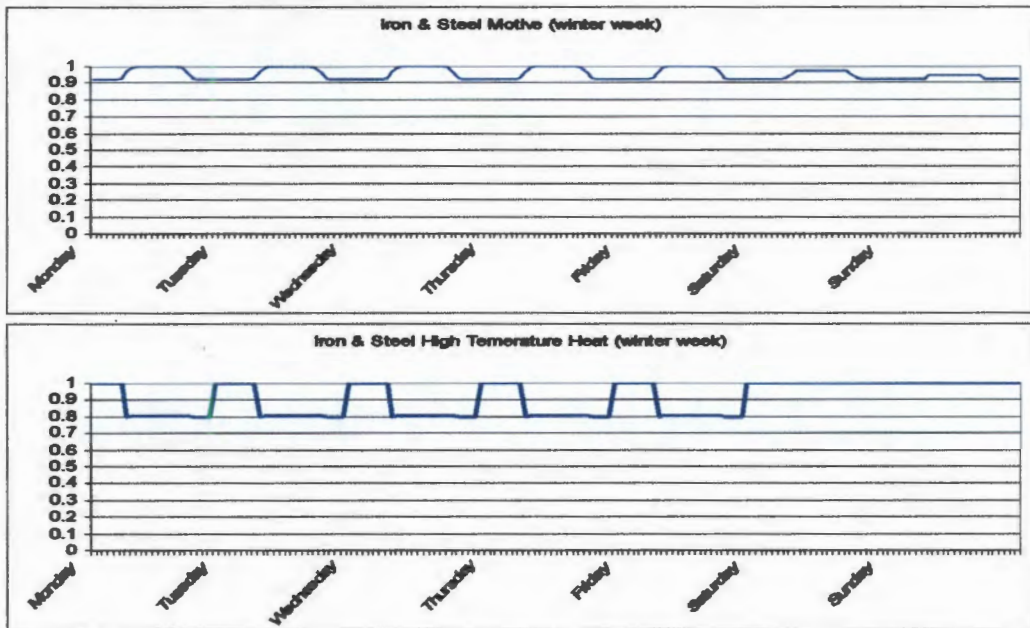


Figure 10-5 Food industry end-use per unit weekly load profiles (1-7 figures)

10.6 Iron & Steel load profiles



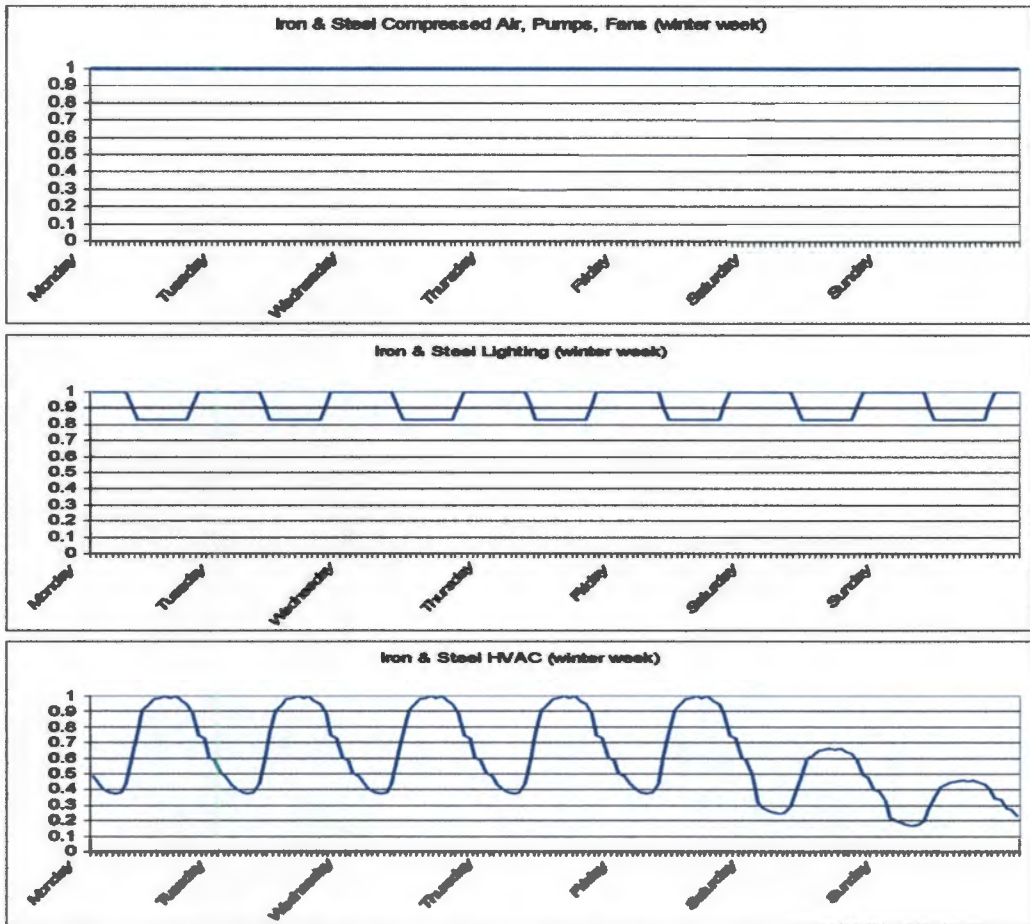
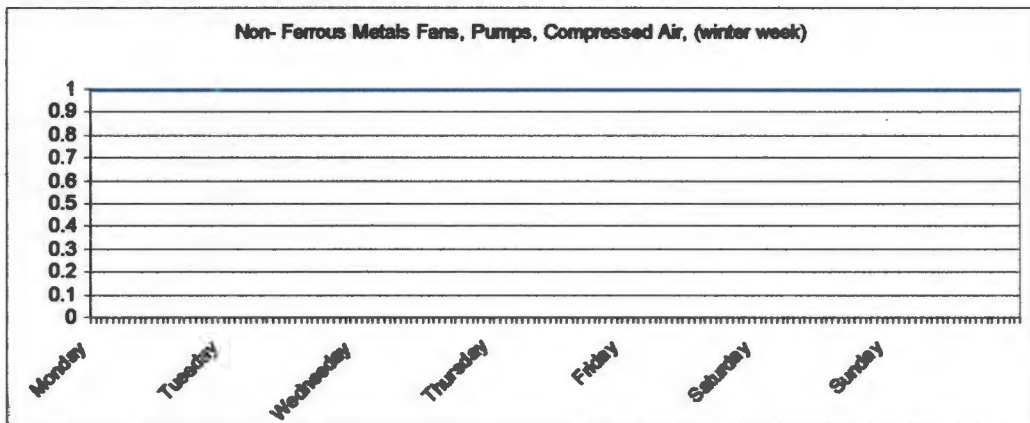


Figure 10-6 Iron and Steel industry end-use per unit weekly load profiles (1-5 figures)

10.7 Non-Ferrous Metals Load Profile



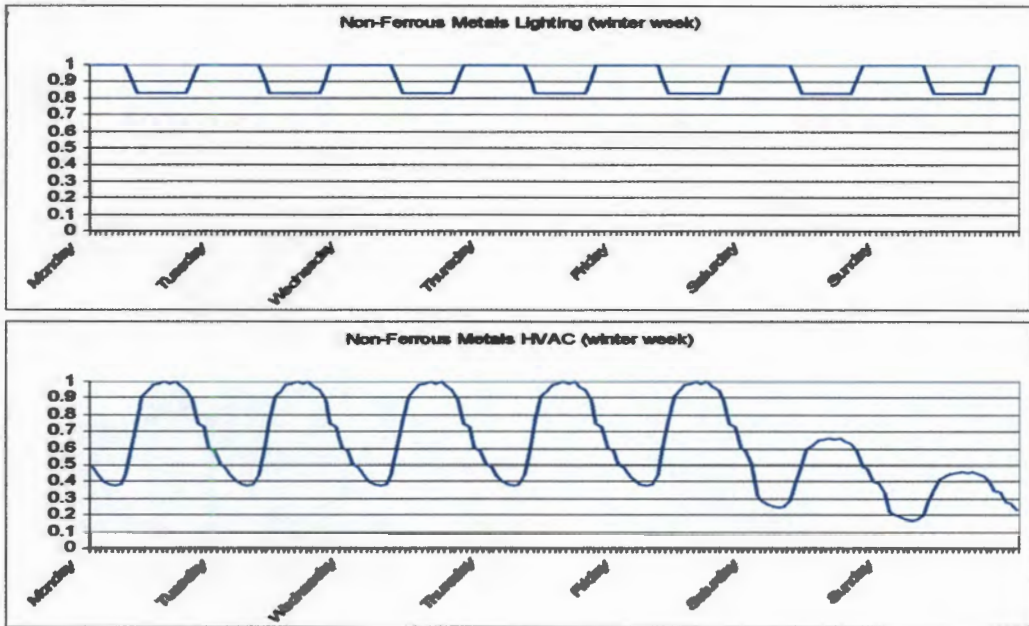
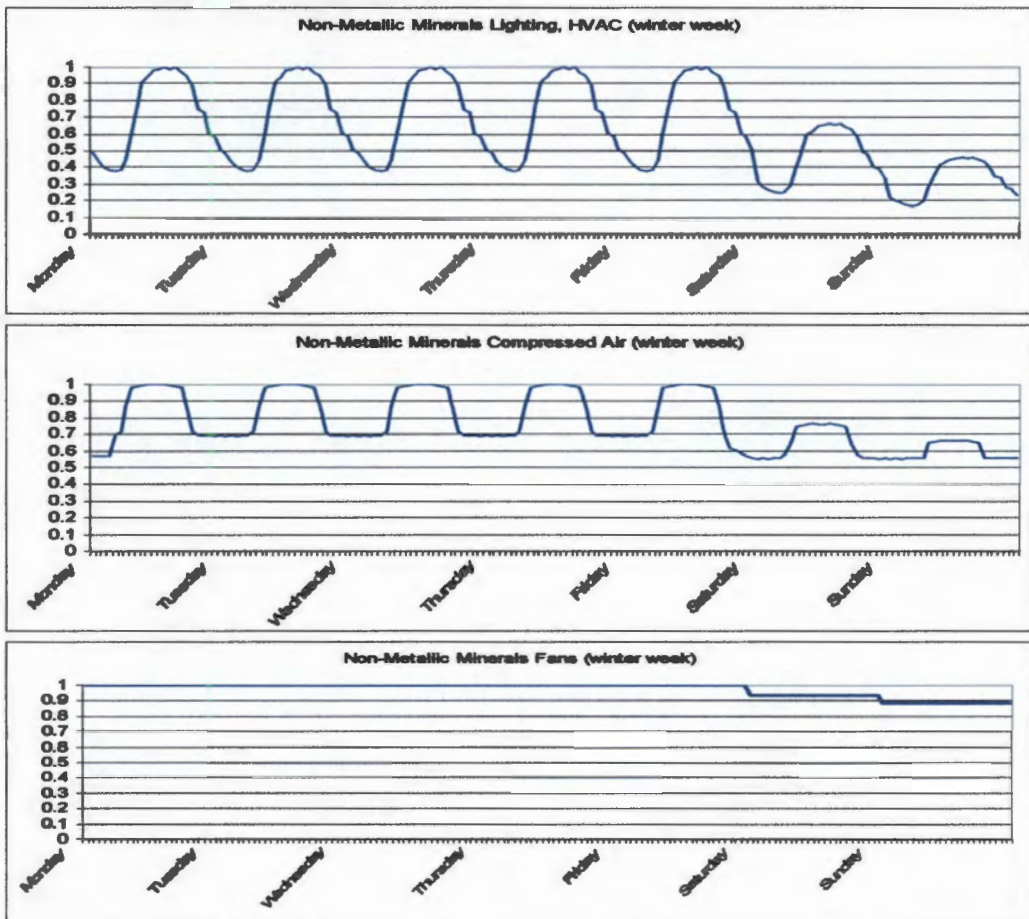


Figure 10-7 Non-ferrous metals industry end-use per unit weekly load profiles (1-3 figures)

10.8 Non-Metallic Minerals Load Profile



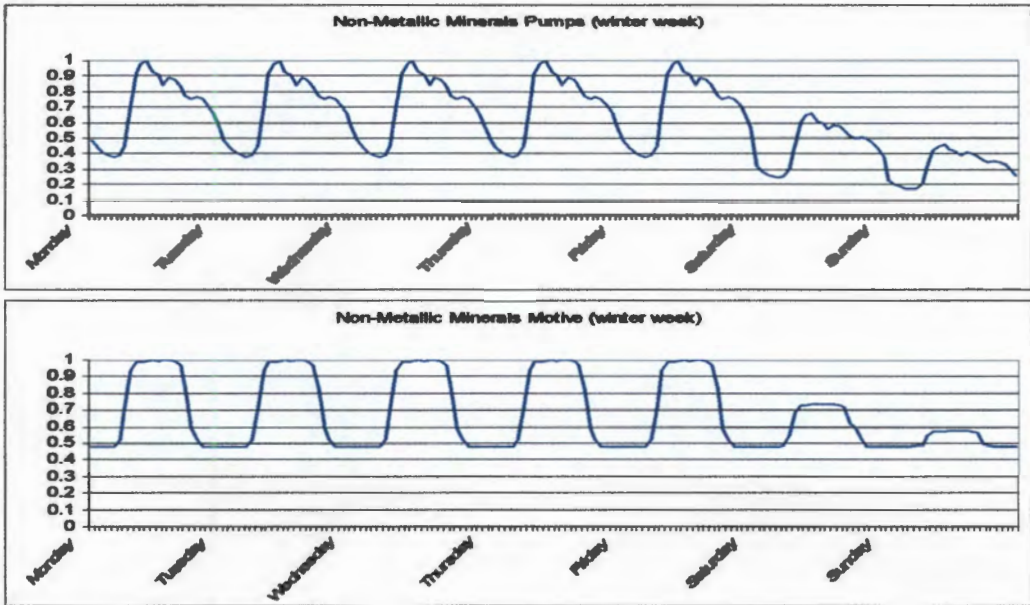
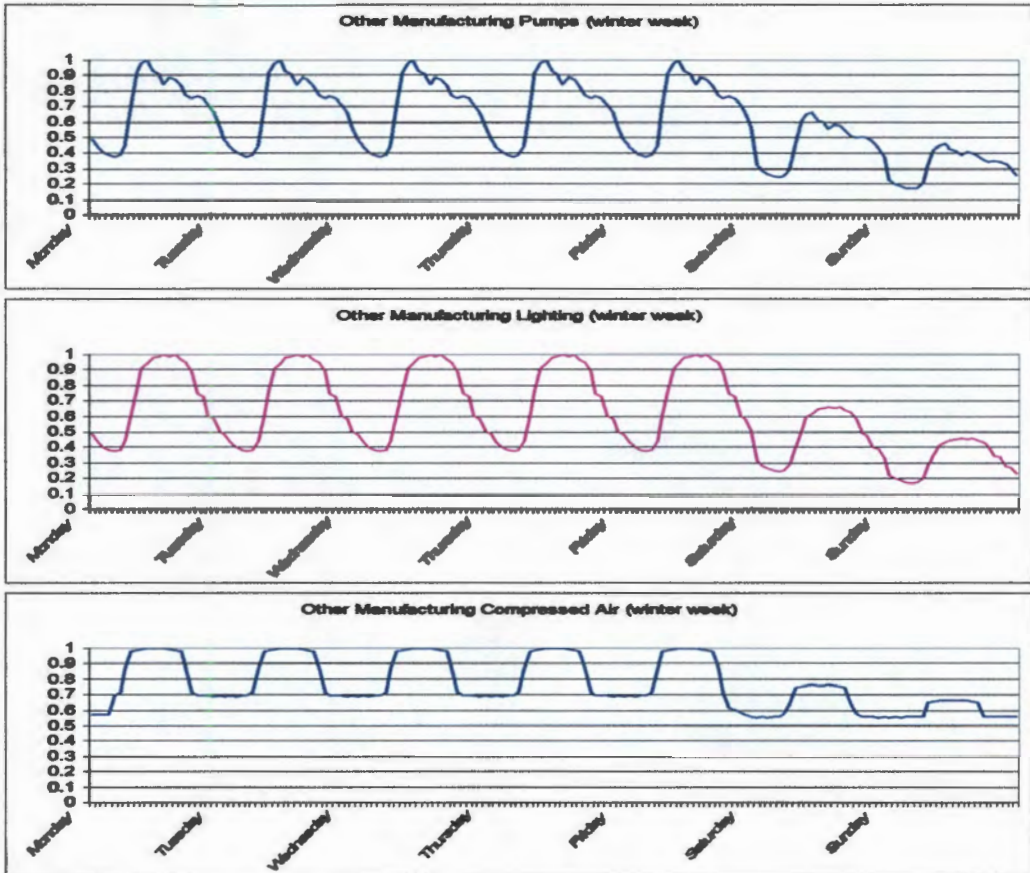


Figure 10-8 Non-metallic minerals industry end-use per unit weekly load profiles (1-5 figures)

10.9 Other Manufacturing Load Profiles



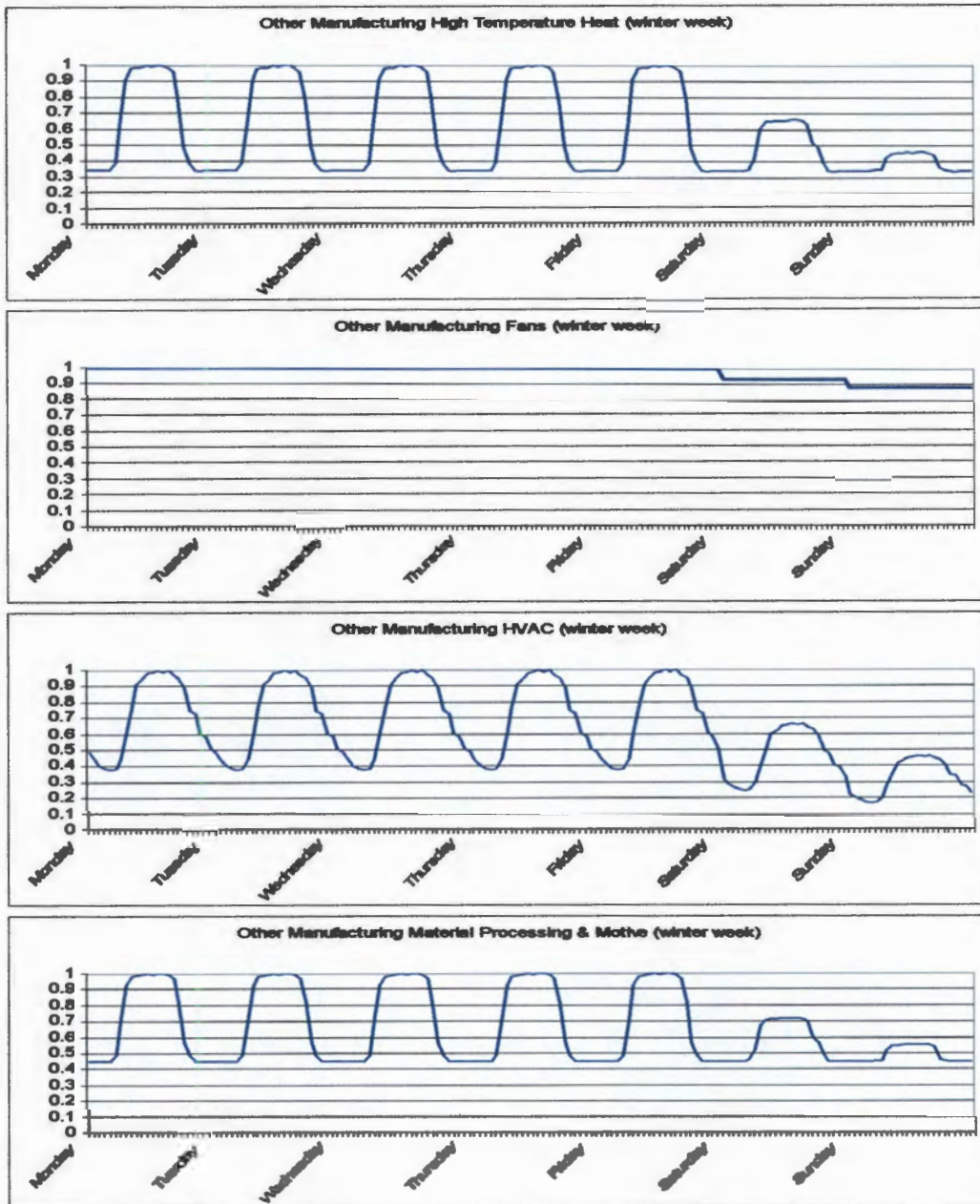
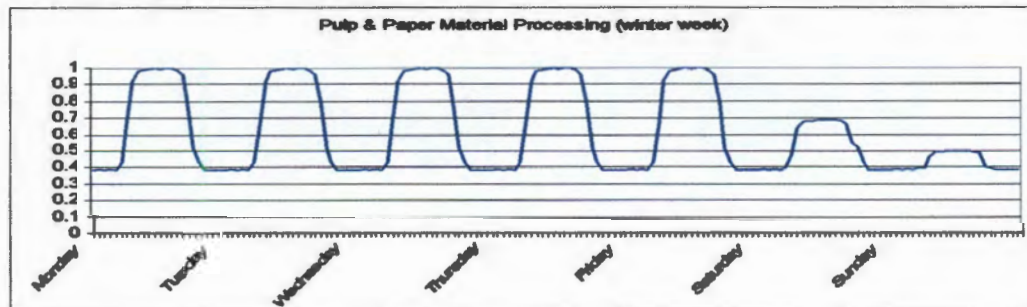


Figure 10-9 Other manufacturing industry end-use per unit weekly load profiles (1-7 figures)

10.10 Pulp & Paper Load Profiles



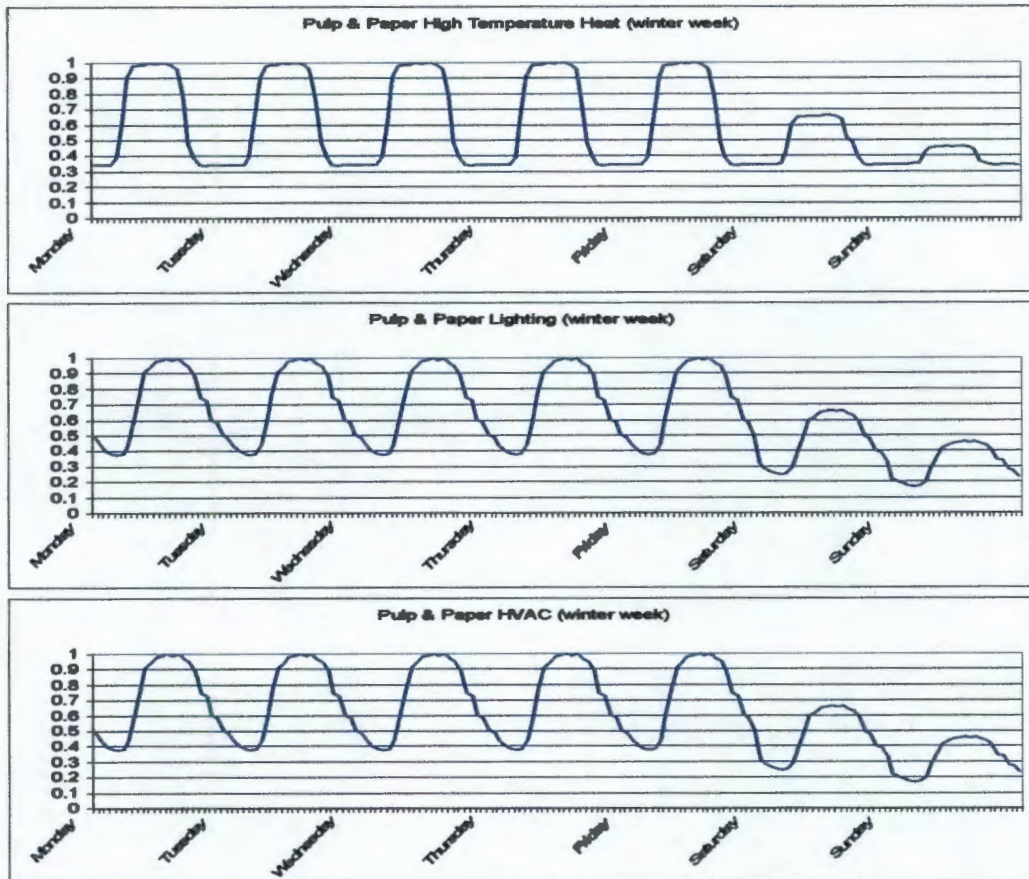
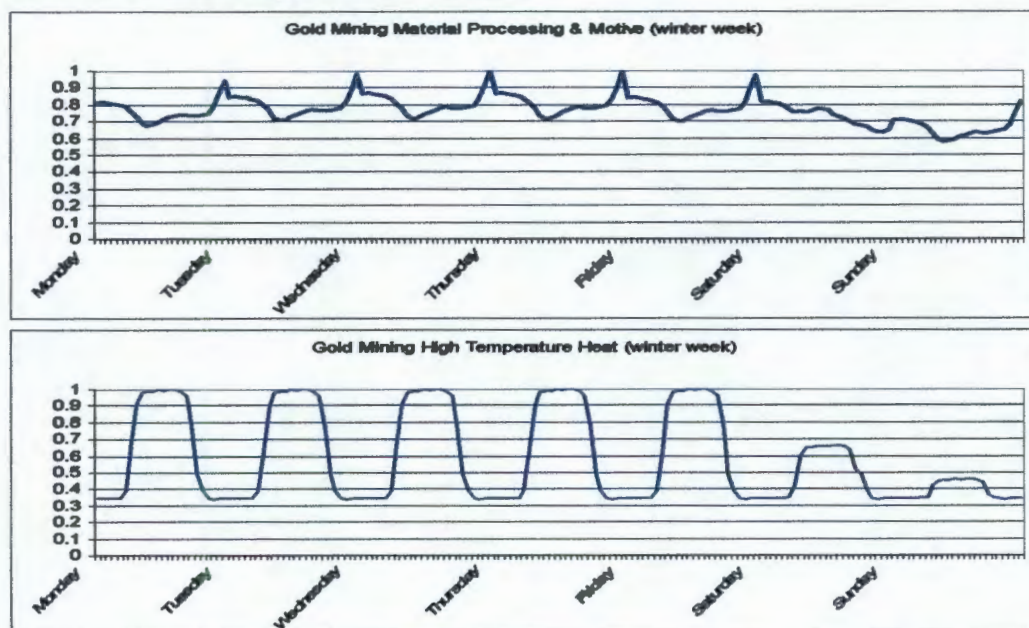
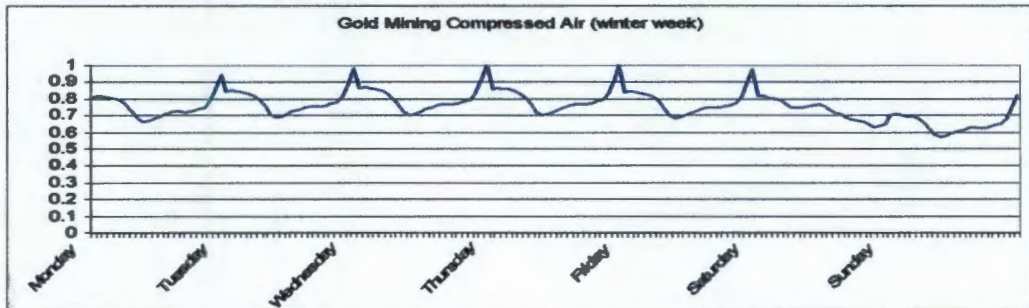
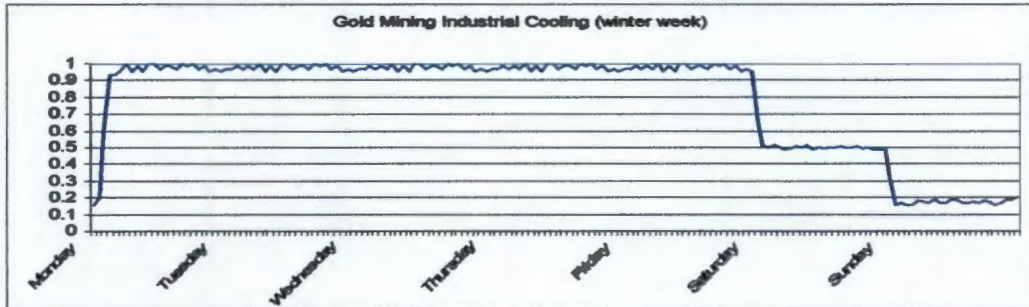
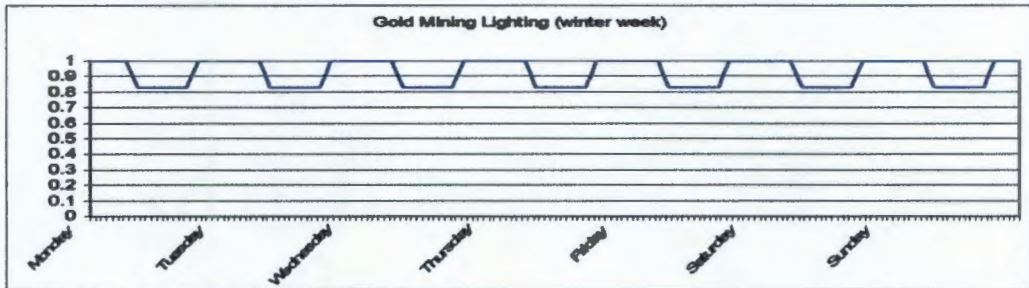
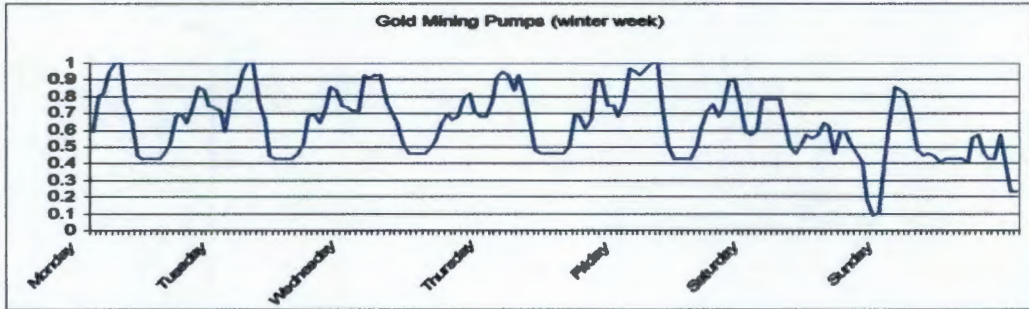
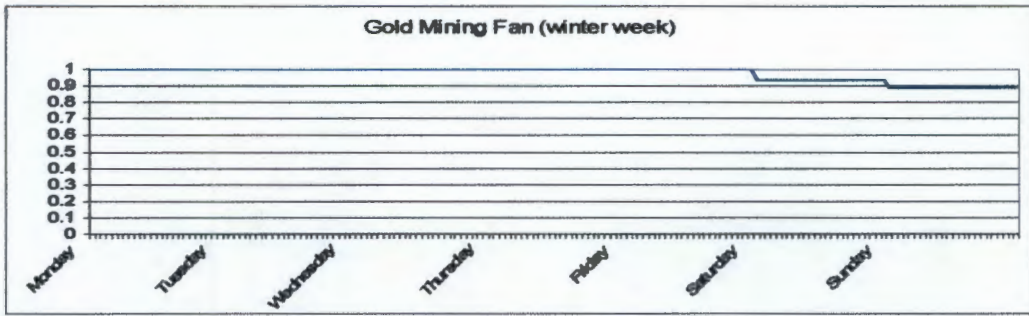


Figure 10-10 Pulp, paper and printing industry end-use per unit weekly load profiles (1-4 figures)

10.11 Gold Mining Load Profiles





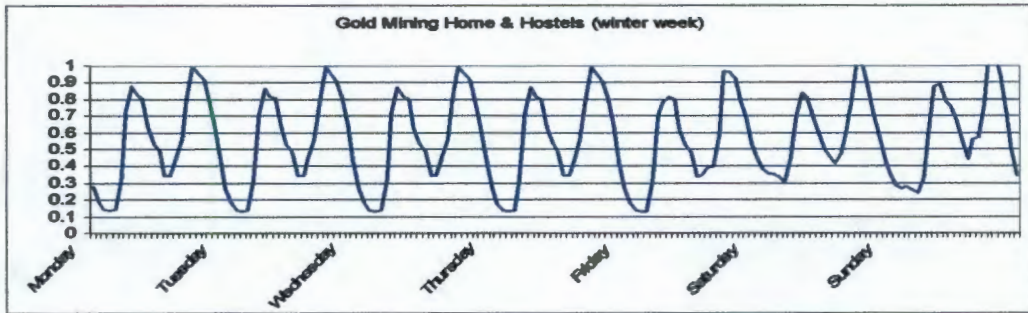
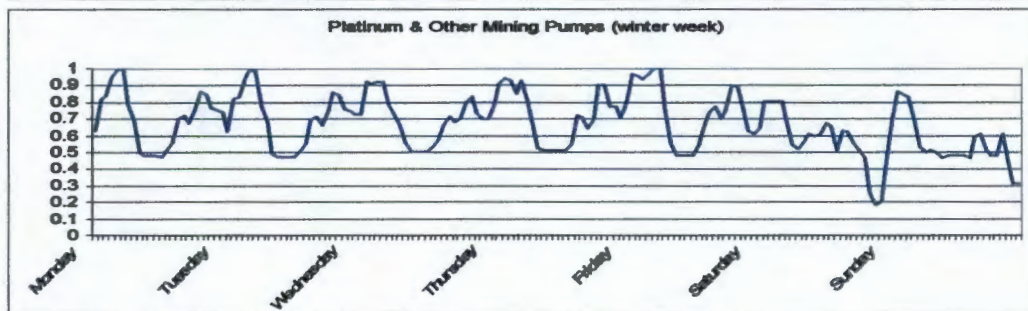
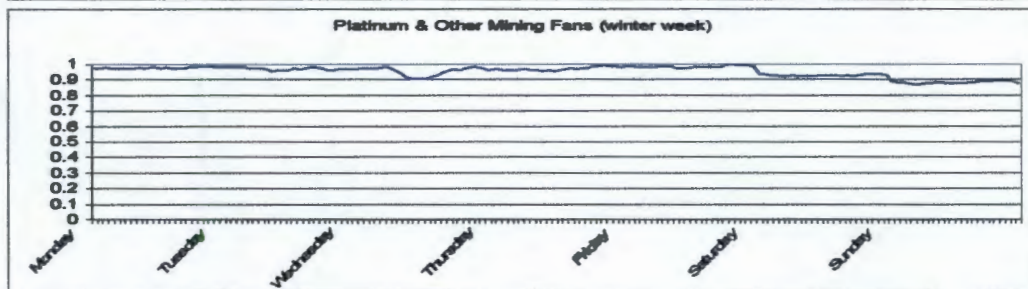
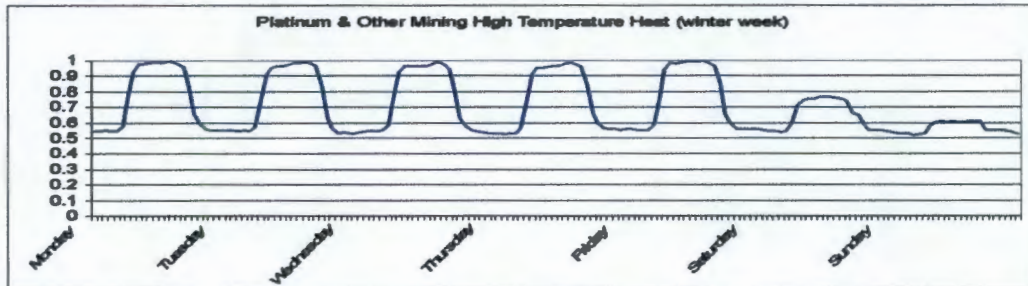
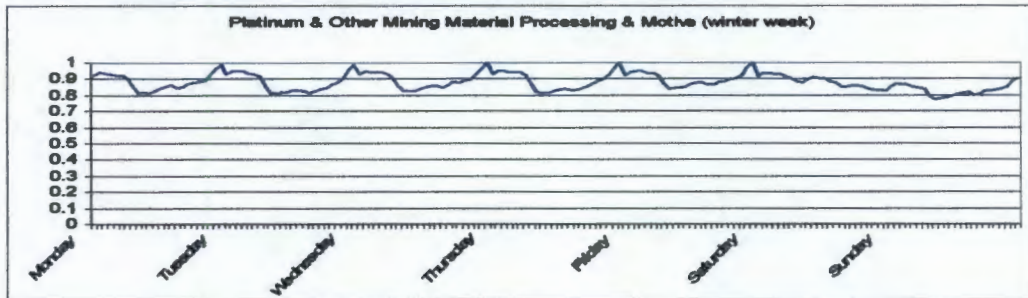


Figure 10-11 Gold mining end-use per unit weekly load profiles (1-8 figures)

10.12 Platinum & Other Mining Load Profiles



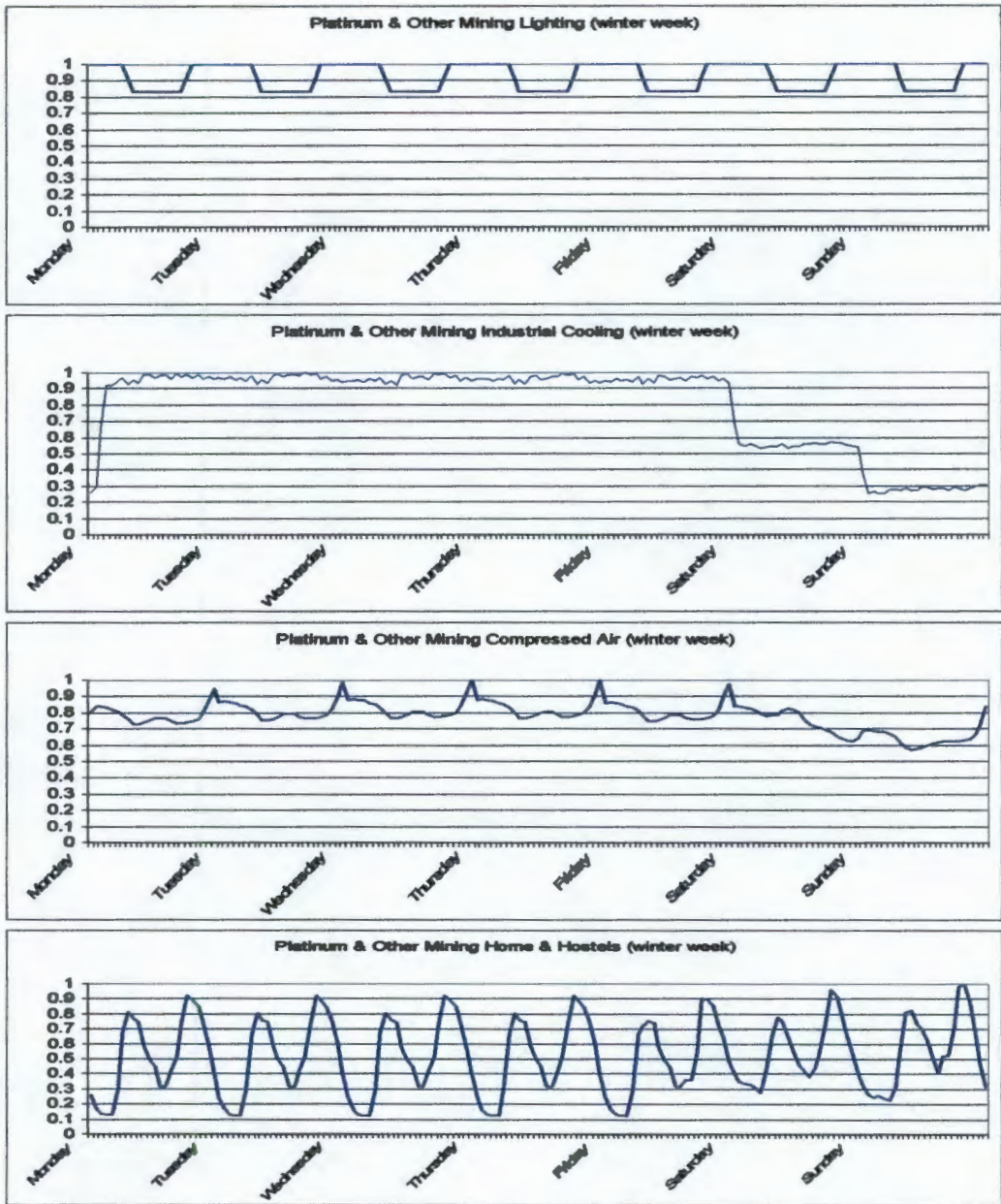
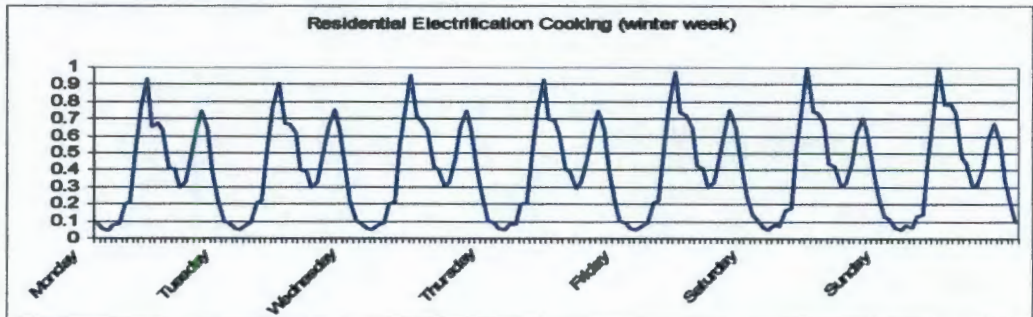


Figure 10-12 Platinum and other mining end-use per unit weekly load profiles (1-8 figures)

10.13 Residential Electrification Load Profiles



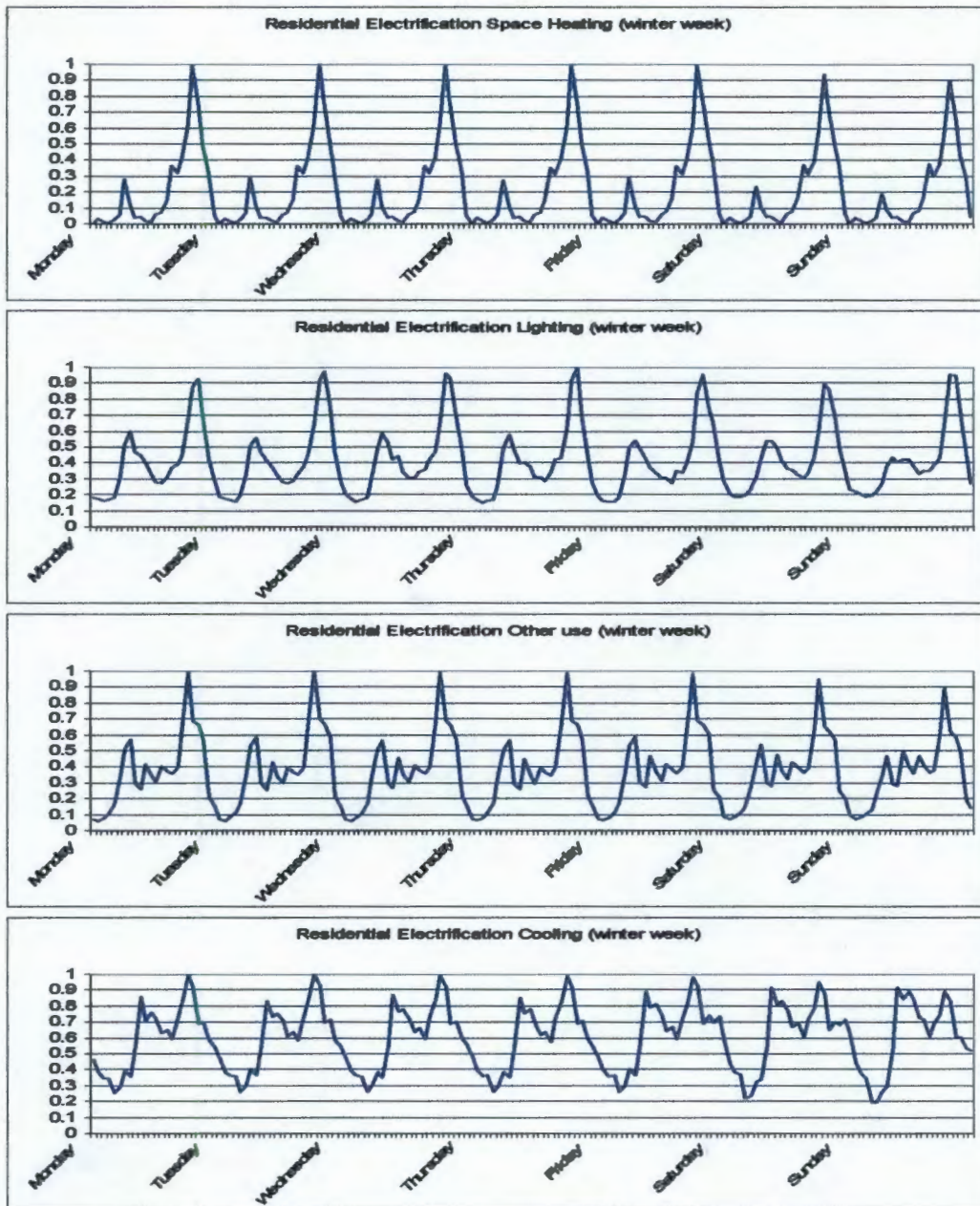
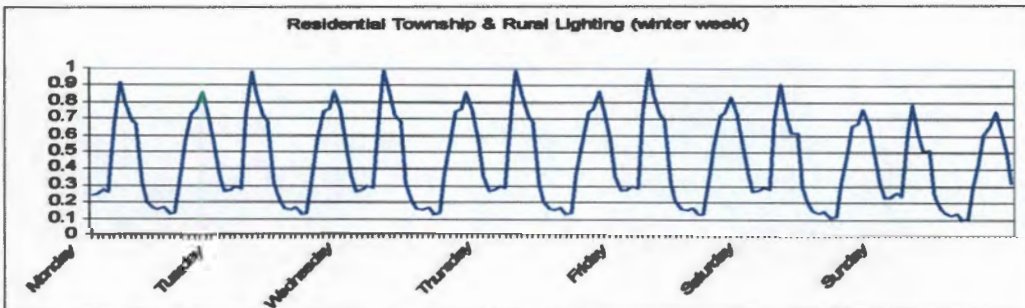
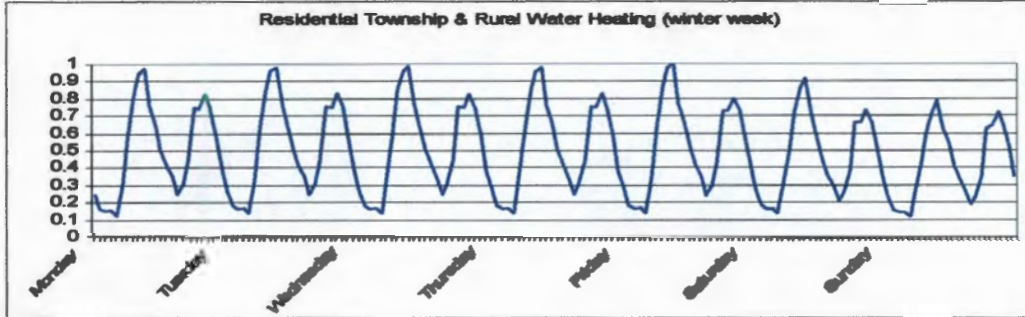
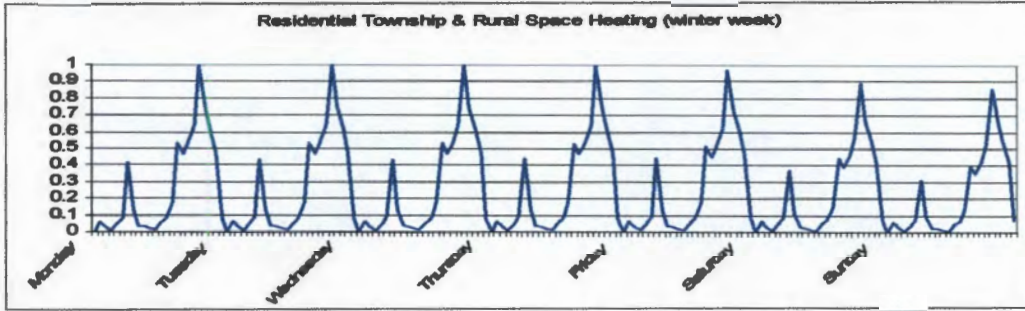
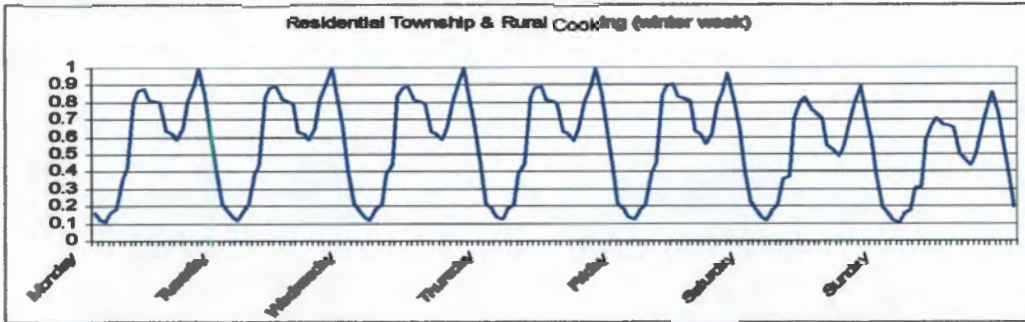


Figure 10-13 Electrification residential end-use per unit weekly load profiles (1-5 figures)

10.14 Residential Township & Rural load profiles



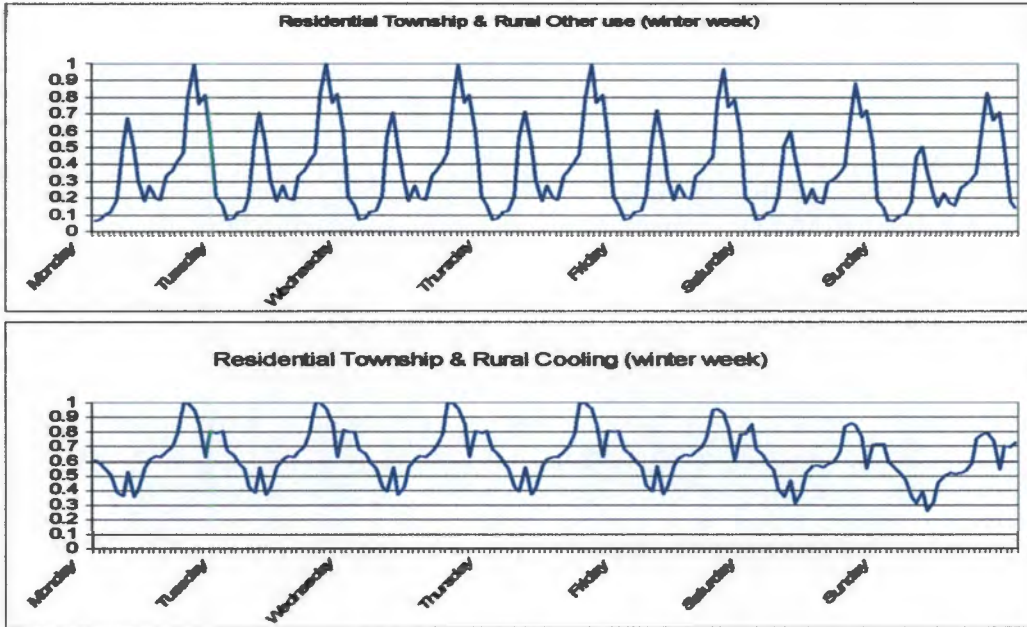
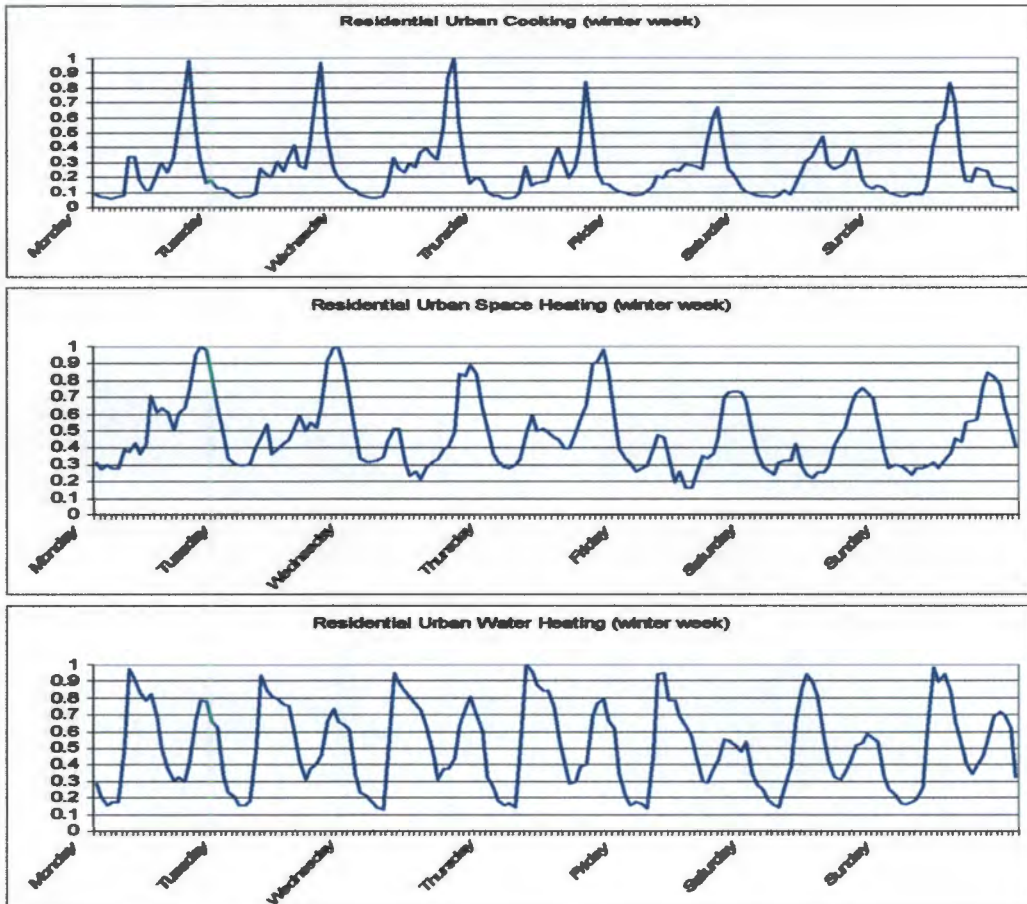


Figure 10-14 Township and rural residential end-use per unit weekly load profiles (1-6 figures)

10.15 Residential Urban Load Profiles



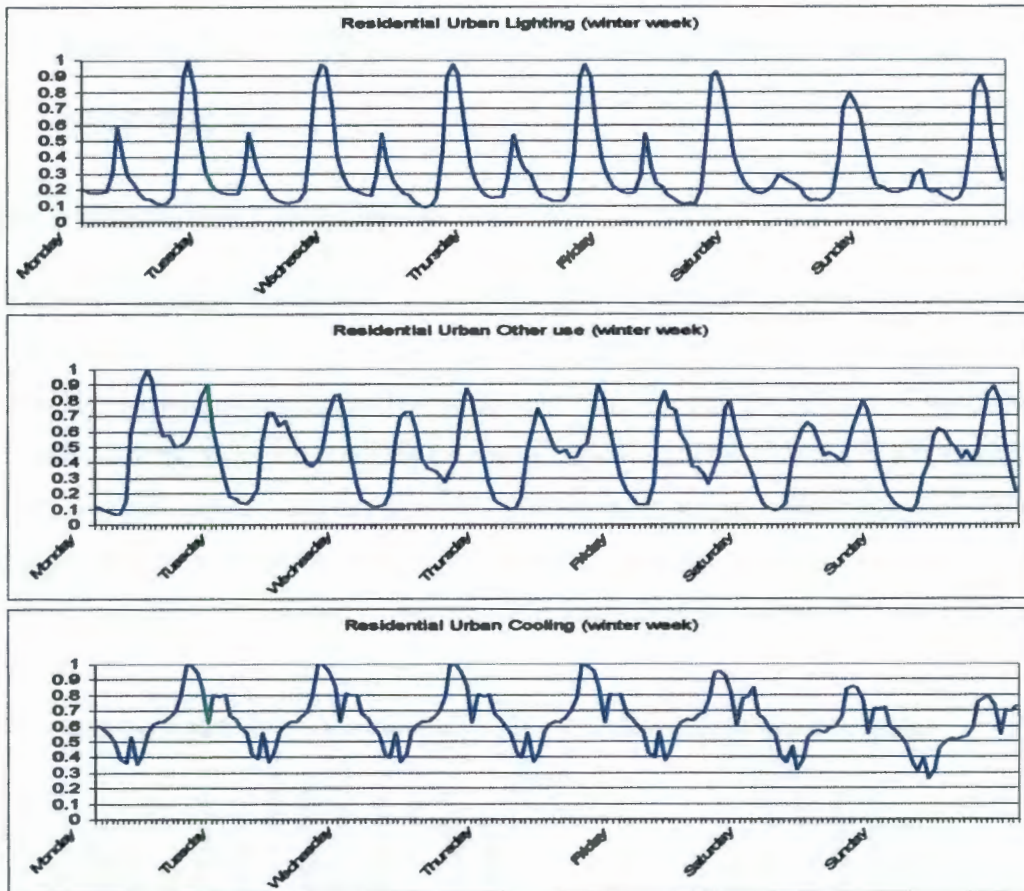


Figure 10-15 Urban residential end-use per unit weekly load profiles (1-6 figures)

10.16 Transport load profile

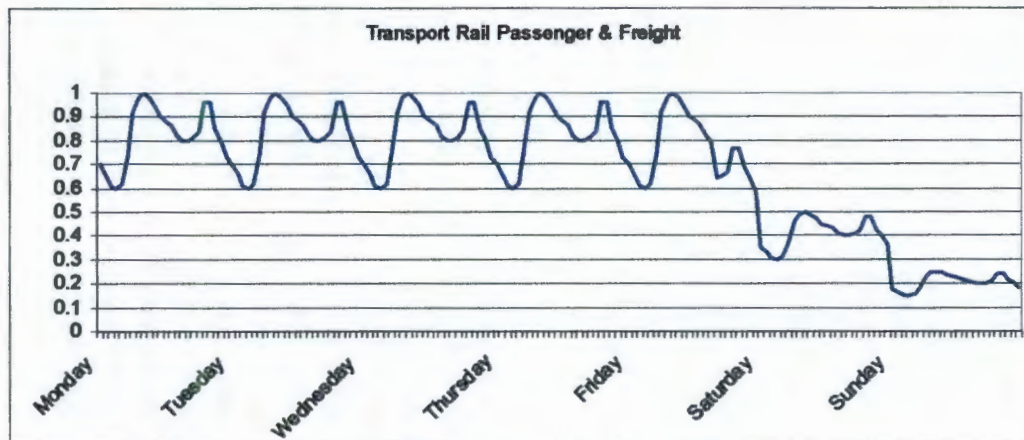


Figure 10-16 Transport rail end-use per unit weekly load profile

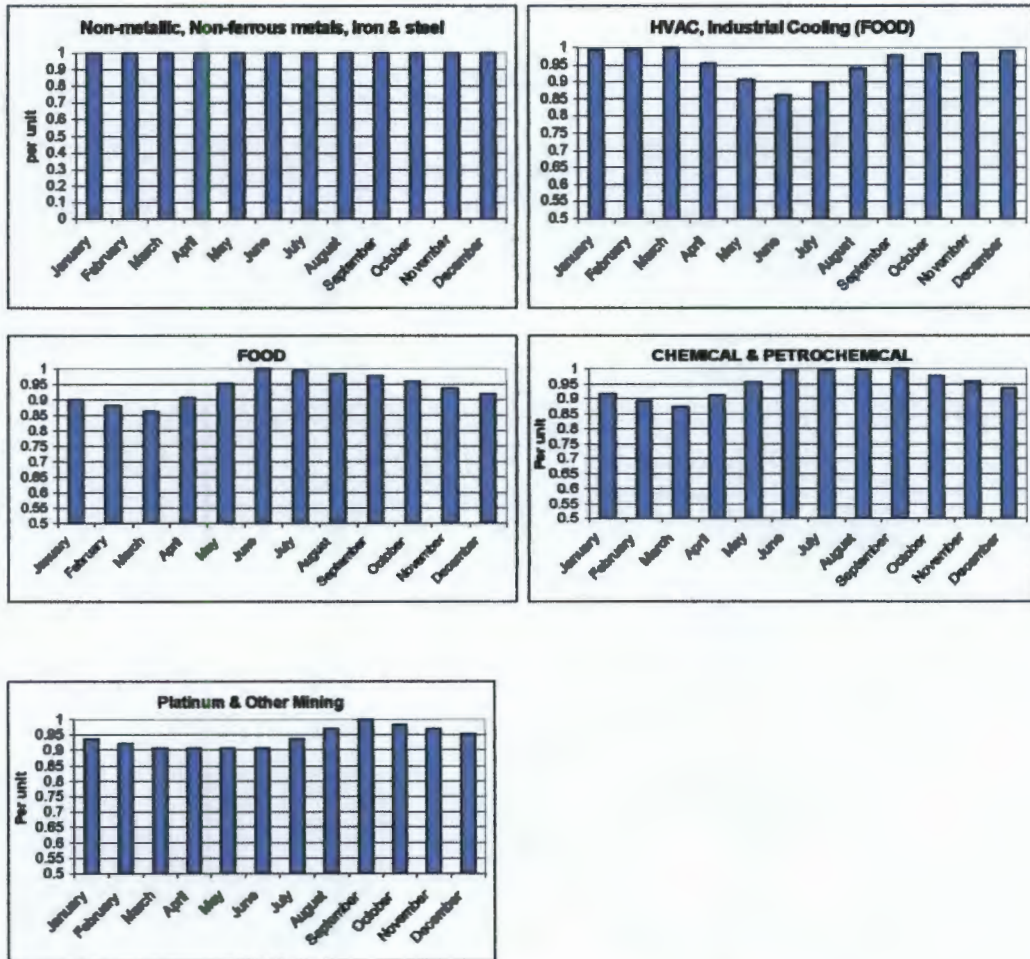


Figure 11-1 Monthly load utilisation for commerce and industry (11 figures)

GOLD MINING	January	February	March	April	May	June	July	August	September	October	November	December
compressed air	1.00	1.00	1.00	0.96	1.00	0.98	0.96	0.99	0.99	1.00	1.00	1.00
fans	0.94	0.94	0.94	0.96	0.95	1.00	1.00	0.98	0.97	0.95	0.94	0.94
pumping	1.00	1.00	1.00	0.87	0.92	0.62	0.62	0.71	0.81	0.90	1.00	1.00
refrigeration	0.82	0.82	0.82	0.88	0.86	1.00	1.00	0.96	0.91	0.87	0.82	0.82
winding	0.82	0.82	0.82	0.88	0.86	1.00	1.00	0.95	0.91	0.86	0.82	0.82
mining	1.00	1.00	1.00	0.91	0.94	0.73	0.73	0.80	0.87	0.93	1.00	1.00
metallurgy	0.94	0.94	0.94	0.96	0.95	1.00	1.00	0.98	0.97	0.95	0.94	0.94
homes	0.57	0.58	0.59	0.71	0.83	0.95	1.00	0.95	0.83	0.71	0.59	0.58
Material processing	1.00	1.00	1.00	0.93	0.95	0.79	0.79	0.84	0.88	0.95	1.00	1.00

Table 11-1 Gold mining monthly load variations

Urban Residential	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
cooking	0.70	0.72	0.73	0.81	0.88	0.95	1.00	0.95	0.88	0.81	0.73	0.72
water heating	0.69	0.71	0.73	0.80	0.88	0.95	1.00	0.95	0.88	0.80	0.73	0.71
space heating	0.00	0.00	0.00	0.32	0.63	0.95	1.00	0.95	0.63	0.32	0.00	0.00
lighting	0.87	0.89	0.91	0.92	0.94	0.95	1.00	0.95	0.94	0.92	0.91	0.89
cooling	0.83	0.85	0.87	0.90	0.92	0.95	1.00	0.95	0.92	0.90	0.87	0.85
other	0.41	0.42	0.43	0.60	0.78	0.95	1.00	0.95	0.78	0.60	0.43	0.42

Table 11-2 Urban residential monthly load variations

Township & Rural Residential	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
cooking	0.47	0.48	0.49	0.64	0.80	0.95	1.00	0.95	0.80	0.64	0.49	0.48
water heating	0.56	0.58	0.59	0.71	0.83	0.95	1.00	0.95	0.83	0.71	0.59	0.58
space heating	0.00	0.00	0.00	0.32	0.63	0.95	1.00	0.95	0.63	0.32	0.00	0.00
lighting	0.86	0.88	0.91	0.92	0.94	0.95	1.00	0.95	0.94	0.92	0.91	0.88
cooling	1.00	0.98	0.95	0.90	0.84	0.79	0.75	0.79	0.84	0.90	0.95	0.98
other	0.48	0.49	0.50	0.65	0.80	0.95	1.00	0.95	0.80	0.65	0.50	0.49

Table 11-3 Township and rural residential monthly load variations

Electrification Residential	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
cooking	0.46	0.48	0.49	0.64	0.80	0.95	1.00	0.95	0.80	0.64	0.49	0.48
space heating	0.00	0.00	0.00	0.32	0.63	0.95	1.00	0.95	0.63	0.32	0.00	0.00
lighting	0.88	0.90	0.93	0.93	0.94	0.95	1.00	0.95	0.94	0.93	0.93	0.90
cooling	0.86	0.88	0.90	0.92	0.93	0.95	1.00	0.95	0.93	0.92	0.90	0.88
other	0.47	0.49	0.50	0.65	0.80	0.95	1.00	0.95	0.80	0.65	0.50	0.49

Table 11-4 Electrification residential monthly load variations

The tables and figures show that most industrial and commercial loads are not reduced by more than 15% as they are not so affected by weather and the level of activity does not vary greatly. Residential loads are more temperature dependent and their use varies significantly such as space heating that is not used in summer months or water heating that experience over 30% reduction in summer months.

11.2 Yearly load profiles for all sectors 2002

The following yearly load profiles have been calculated from individual end-use weekly and monthly load profiles. Each hour of the year, 8760 hours, has a specific electricity demand, GW.

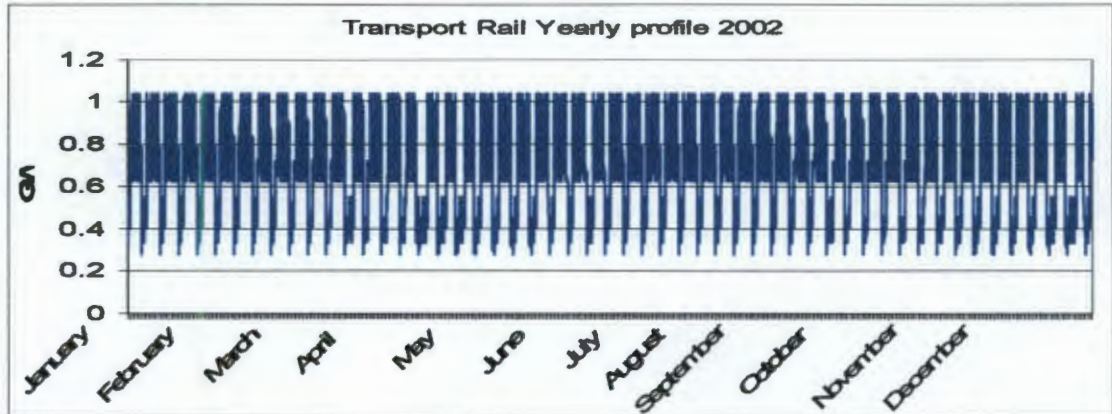


Figure 11-2 Transport yearly load profile 2002

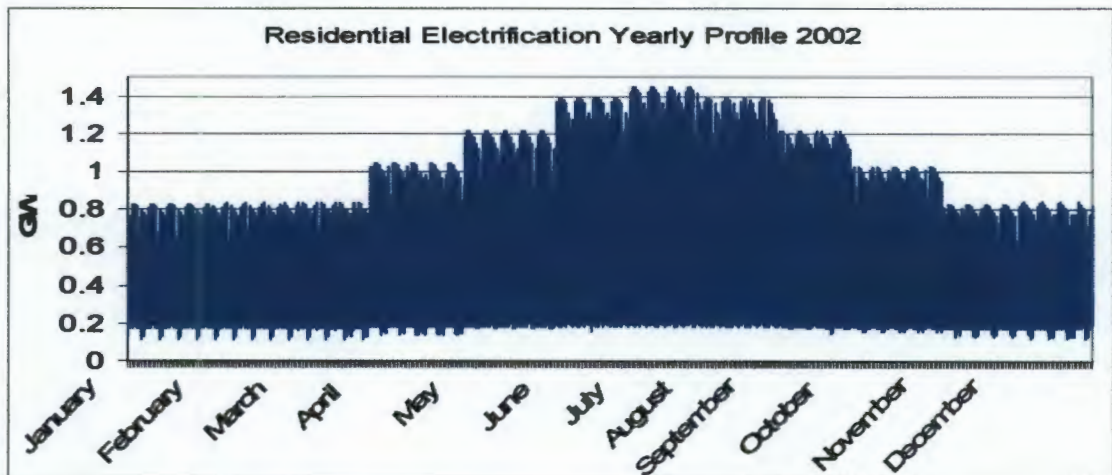


Figure 11-3 Electrification residential yearly load profile 2002

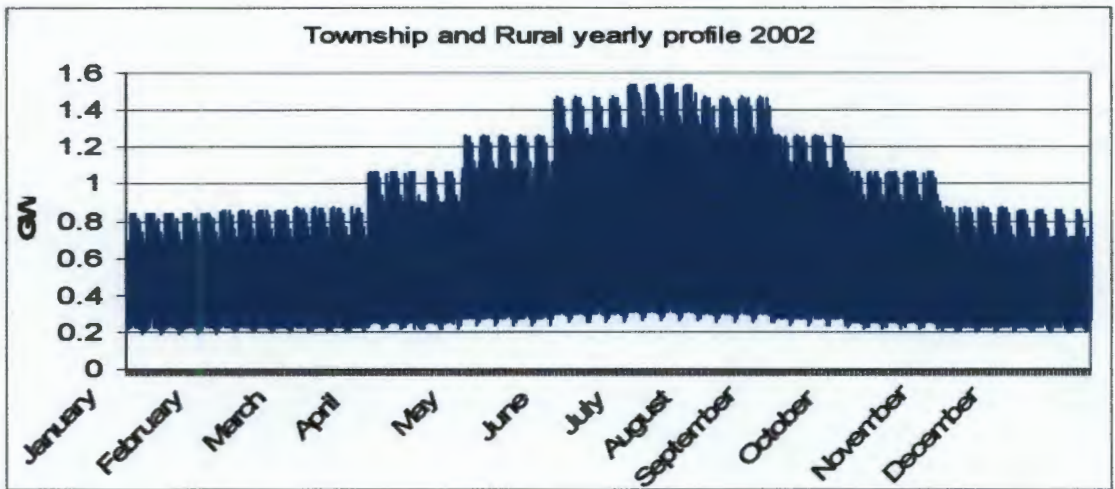


Figure 11-4 Township and rural residential yearly load profile 2002

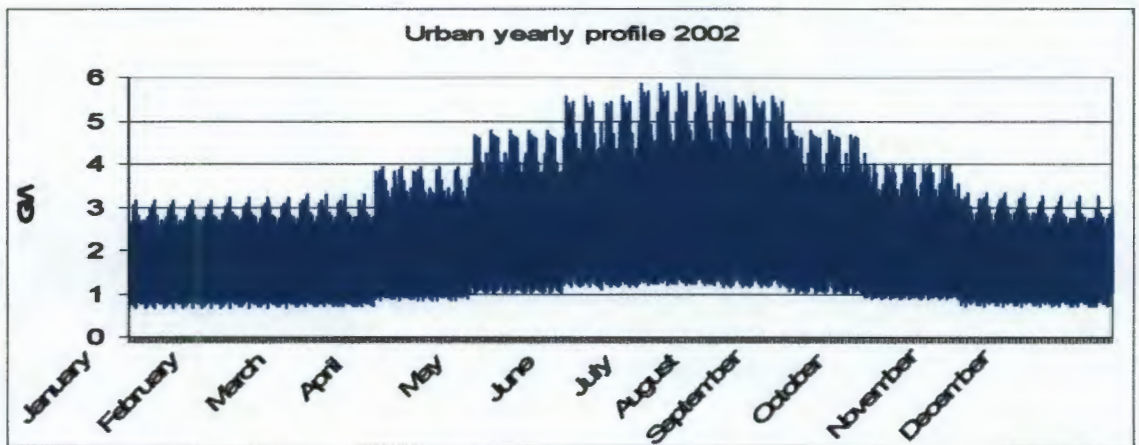


Figure 11-5 Urban residential yearly load profile 2002

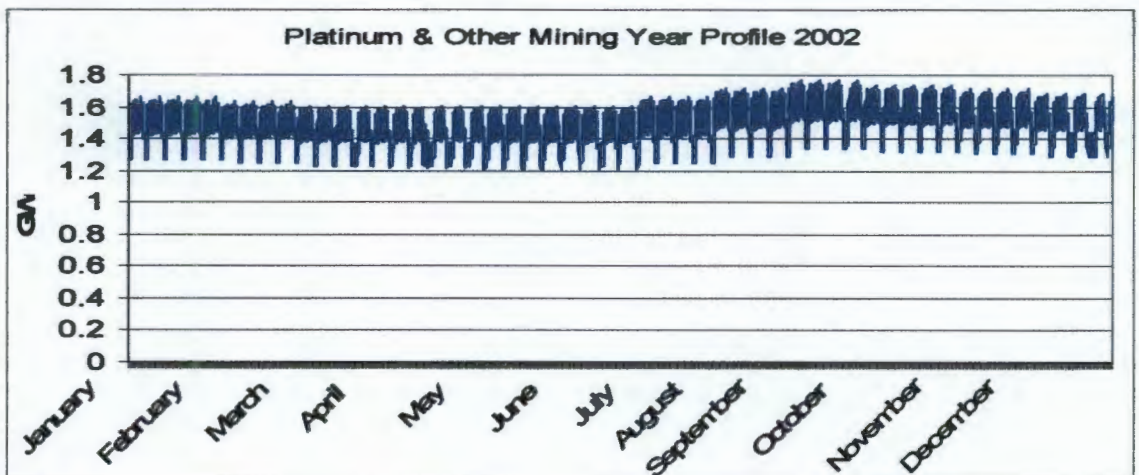


Figure 11-6 Platinum and other mining yearly load profile 2002

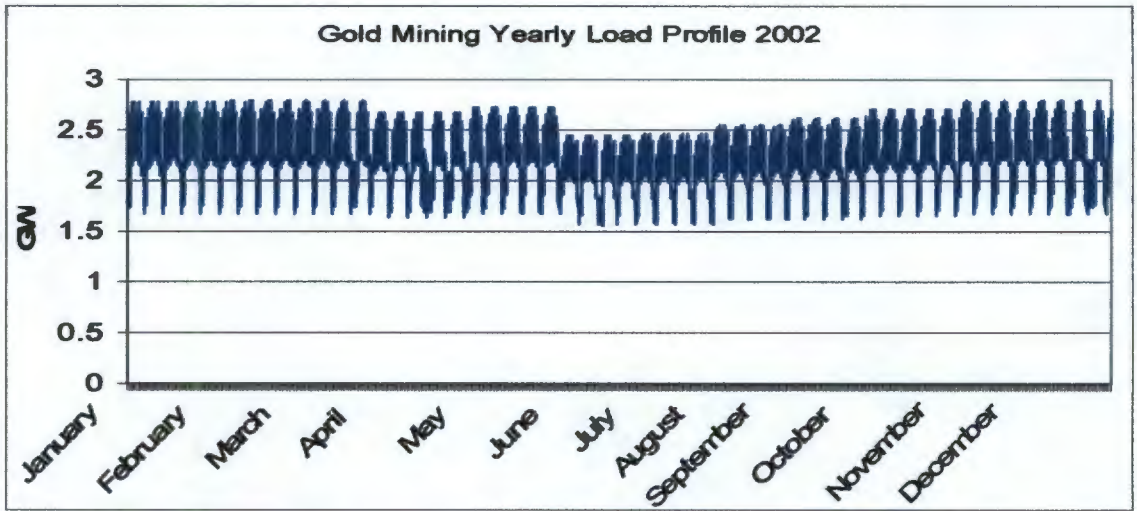


Figure 11-7 Gold mining yearly load profile 2002

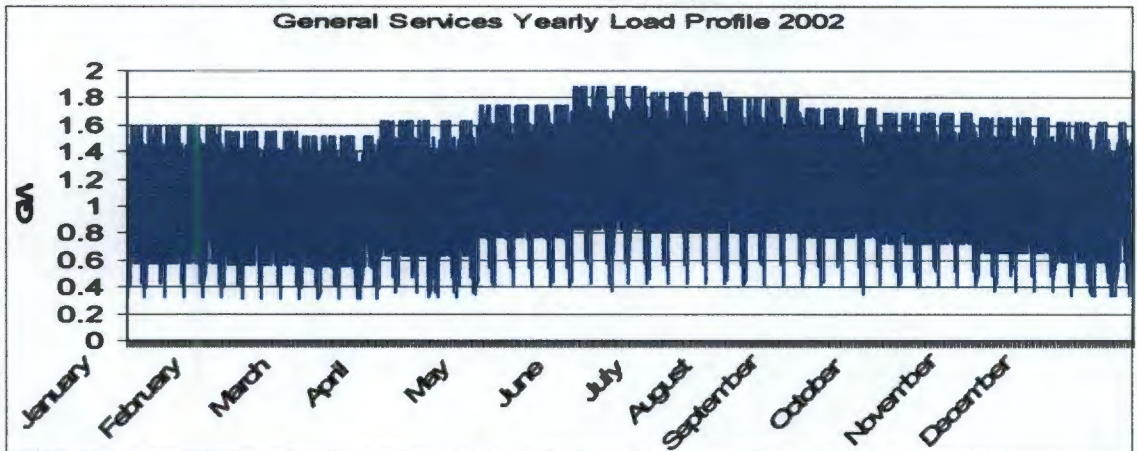


Figure 11-8 General services yearly load profile 2002

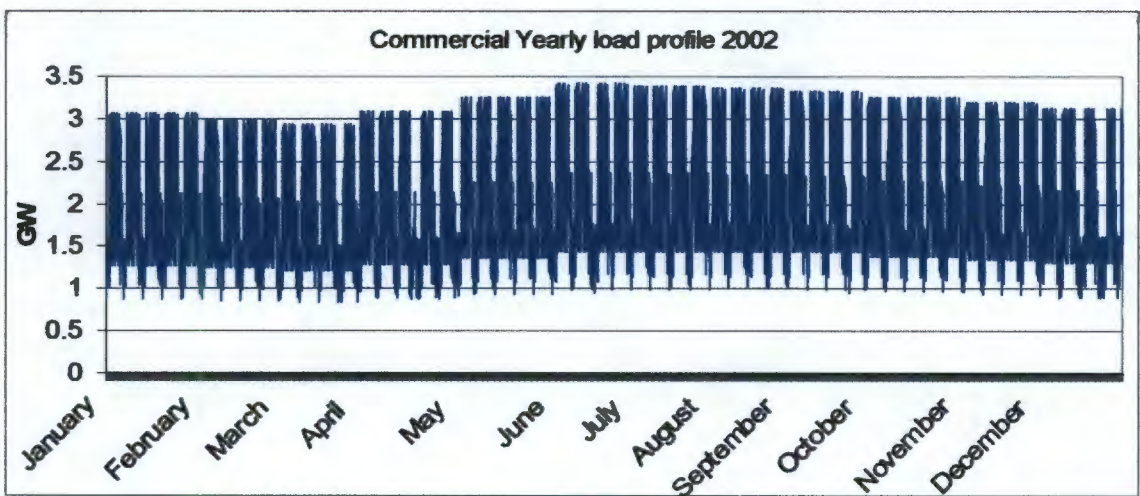


Figure 11-9 Commercial yearly load profile 2002

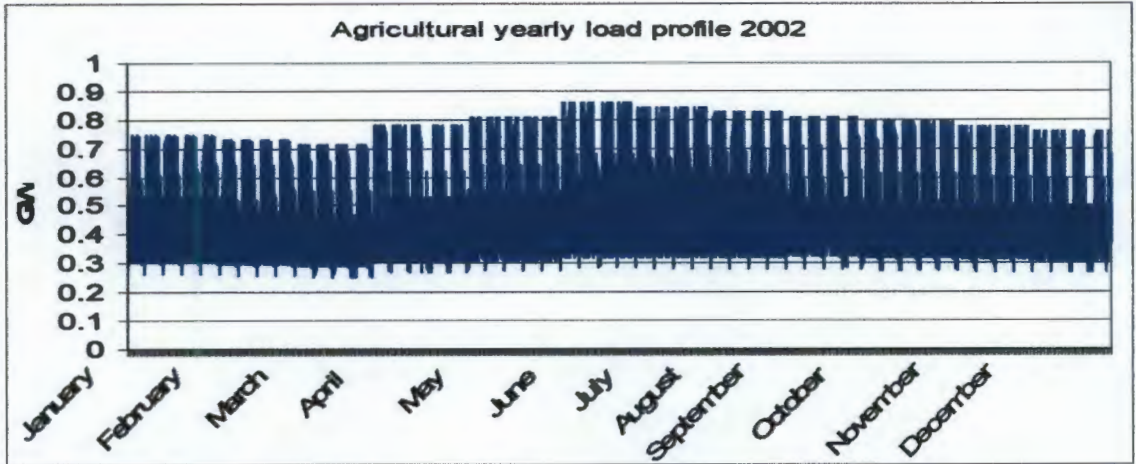


Figure 11-10 Agricultural yearly load profile 2002

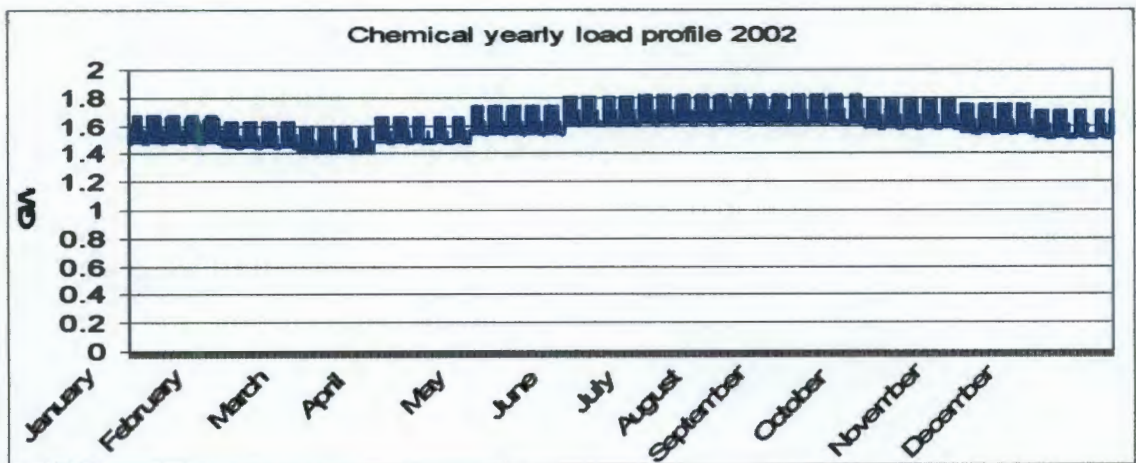


Figure 11-11 Chemicals yearly load profile 2002

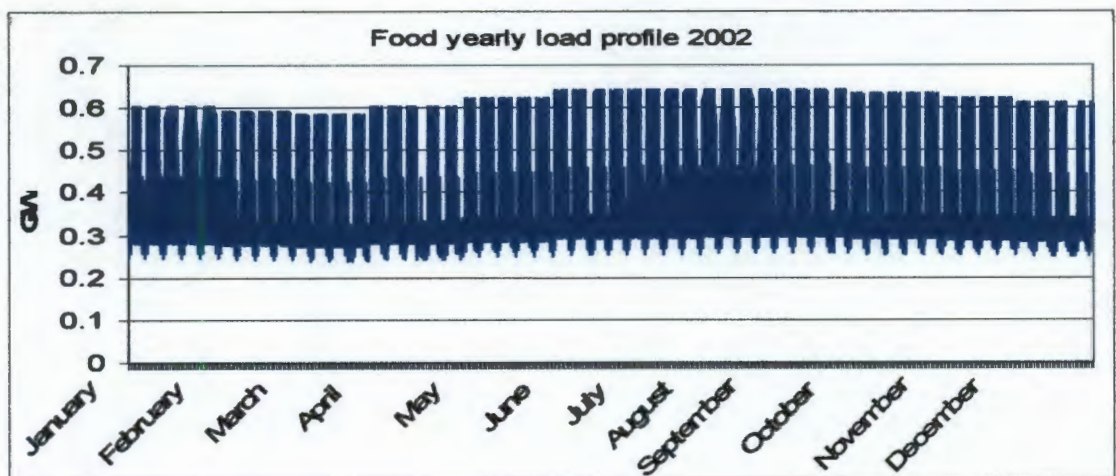


Figure 11-12 Food industry yearly load profile 2002

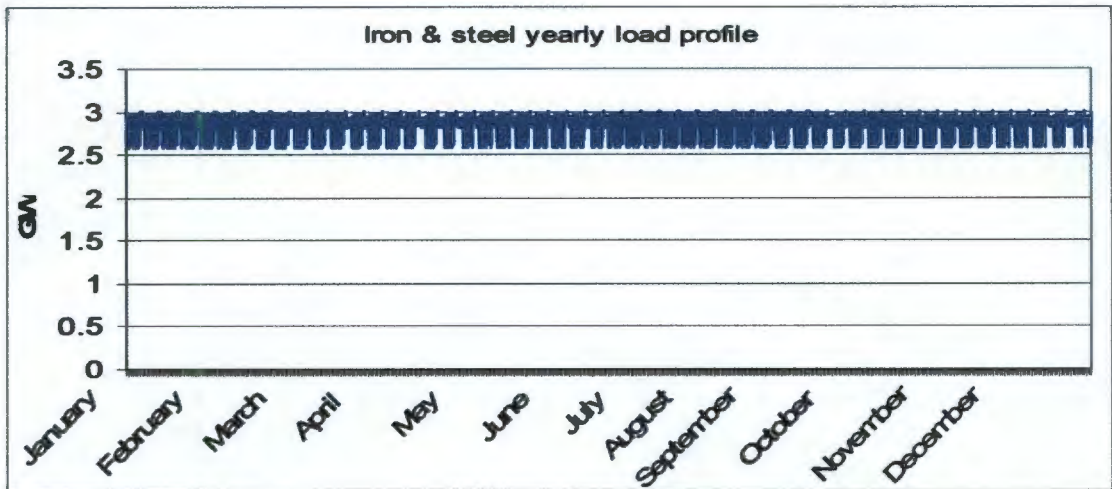


Figure 11-13 Iron and steel industry yearly load profile 2002

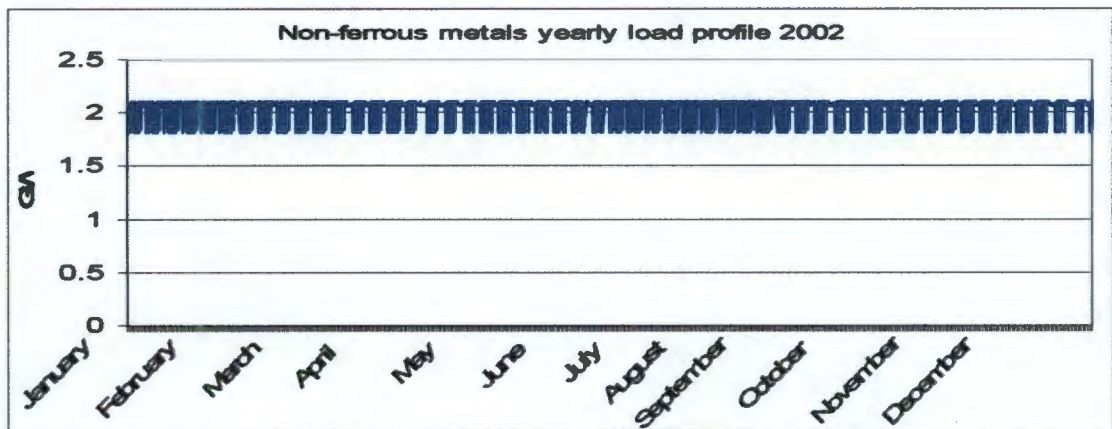


Figure 11-14 Non-ferrous metals industry yearly load profile 2002

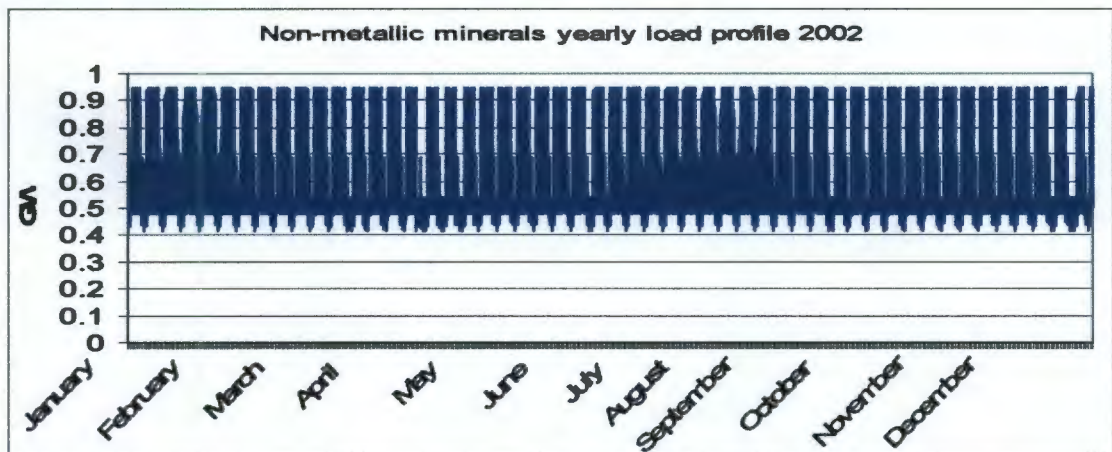


Figure 11-15 Non-metallic industry yearly load profile 2002

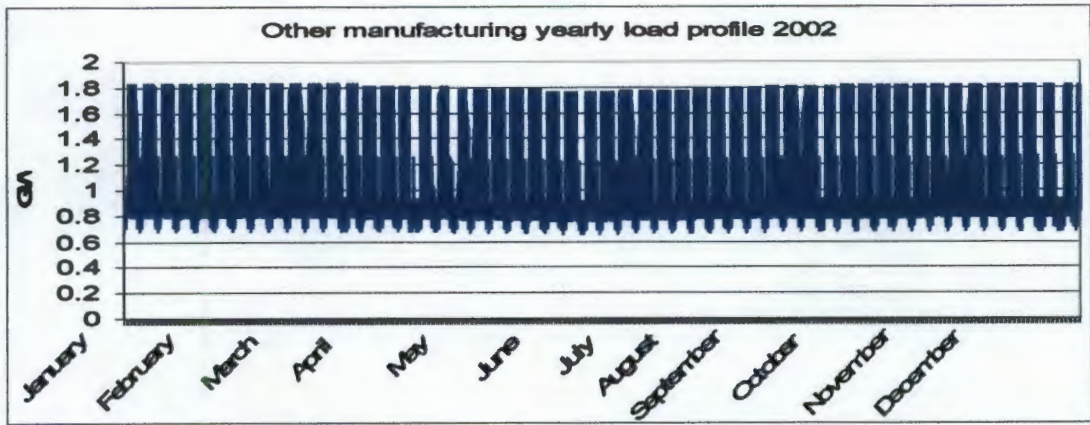


Figure 11-16 Other manufacturing industry yearly load profile 2002

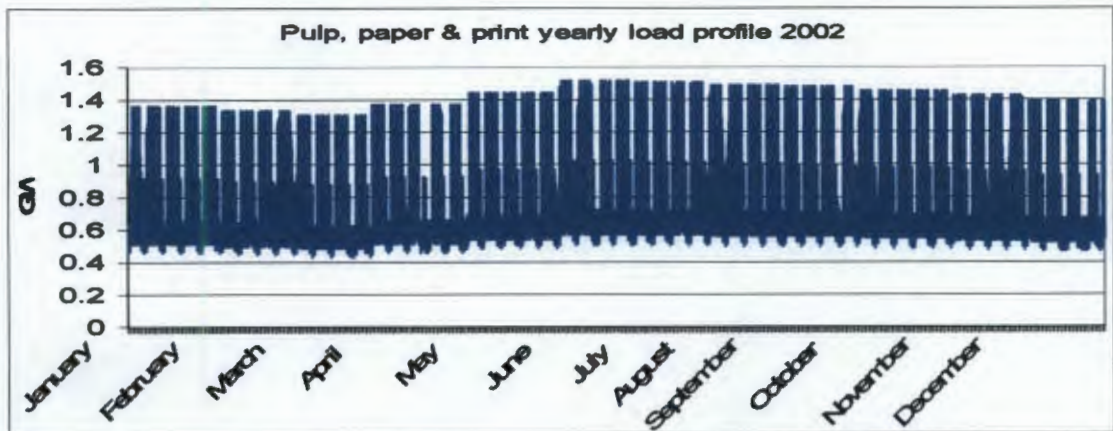


Figure 11-17 Pulp, paper and printing industry yearly load profile 2002

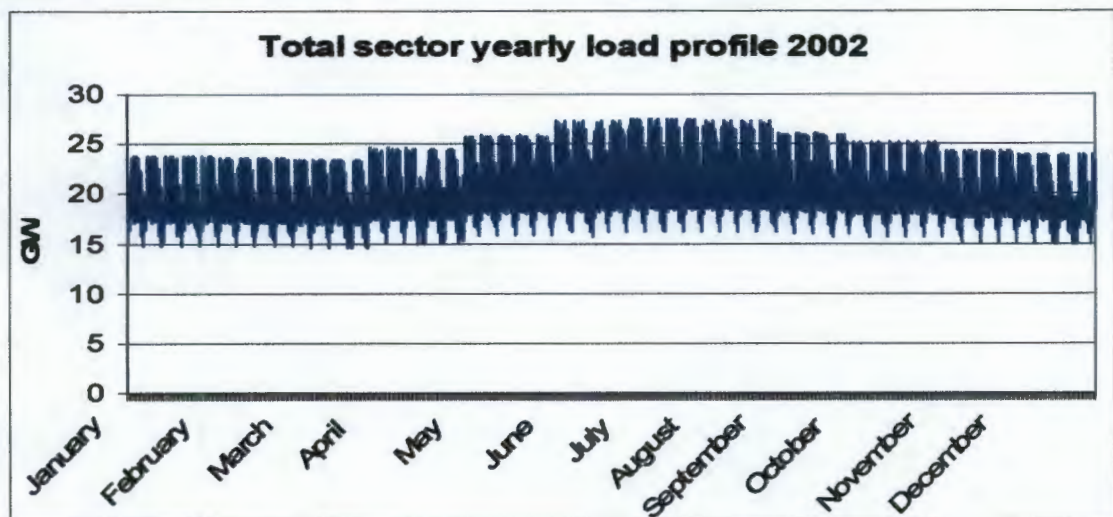


Figure 11-18 Total yearly load profile from all sectors 2002

The total national load for electricity (excluding distribution and transmission losses) varies by 8.5 GW in summer months. There is an 11.5 GW variation in winter mainly because of residential electricity consumption.